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SO2 Emissions in Natural Gas Production Industry Background Information for Promulgated Standards

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Research Triangle Park, NC

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16. ABSTRACT

Standards of performance for the control of sulfur dioxide (SO_2) emissions from the natural gas processing industry are being promulgated under Section 111 of the Clean Air Act. These standards will apply to SO_2 emissions from newly constructed, modified, and reconstructed sweetening and sulfur recovery units in onshore natural gas processing plants. This document summarizes the responses to public comments received on the proposed standards and the basis for changes made since proposal.

17. KEY WORDS AND DOCUMENT ANALYSIS

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SO2 Emissions in Natural Gas Production Industry—Background Information for Promulgated Standards

Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

September 1985

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ENVIRONMENTAL PROTECTION AGENCY

Background Information and Final Environmental Impact Statement for Sulfur Dioxide Emissions from Onshore Natural Gas Processing Plants

Prepared by:

Jack R. Farmer

9/16/85

Jack R. Farmer
Director, Emission Standards and Engineering Division
U. S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

(Date)

1. The promulgated standards of performance will limit emissions of sulfur dioxide from new, modified, and reconstructed sweetening and sulfur recovery units. Section 111 of the Clean Air Act (42 U.S.C 7411), as amended, directs the Administrator to establish standards of performance for any category of new stationary source of air pollution that ". . . causes of contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

2. Copies of this document have been sent to the following Federal Departments: Labor, Health and Human Services, Defense, Transportation, Agriculture, Commerce, Interior, and Energy; the National Science Foundation; the Council on Environmental Quality; State and Territorial Pollution Program Administrators; EPA Regional Administrators; Local Air Pollution Control Officials; Office of Management and Budget; and other interested parties.

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1.0 SUMMARY

On January 20, 1984, the Environmental Protection Agency (EPA) proposed standards of performance for the onshore natural gas processing industry (49 FR 2656) under authority of Section 111 of the Clean Air Act. The standards limit atmospheric emissions of sulfur dioxide (SO_2) from onshore natural gas processing facilities. Public comments were requested on the proposal in the Federal Register. There were 36 commenters composed of industry trade association representatives, industry representatives, plant personnel, and State regulatory agencies. Also included was one process engineering design firm. The public comments along with responses to these comments are summarized in this document. The comments and responses serve as the basis for the revisions made to the standard between proposal and promulgation.

1.1 SUMMARY OF CHANGES SINCE PROPOSAL

In response to the public comments and as a result of reevaluation, certain changes have been made in the proposed standards. The emission reduction efficiency requirement format of the standard has not changed. Control of SO_2 emissions is based on sulfur recovery efficiencies achievable with the technologies selected as representative of best demonstrated technology. The equations used in the calculation of required recovery efficiencies remain the same.

The following are changes made to the standards since proposal:

(1) The proposed 1.0 LT/D cutoff has been changed to a cutoff of 2.0 LT/D. The proposed 1.0 LT/D cutoff was based on an analysis of the incremental cost effectiveness of the technology included in the regulatory alternative on which the standards were based compared to the baseline alternative. This analysis assumed an average capacity utilization of the affected facilities of 100 percent. Based on data

received from commenters, the Agency has determined that average capacity utilization is typically closer to 75 percent. Incorporation of the 75 percent capacity utilization assumption into a revised cost-effectiveness analysis resulted in the 2.0 LT/D cutoff that is being promulgated.

(2) The costs per ton of emission reduction are higher for plants with low H_2S concentrations in the acid gas (relative to the facility's sulfur feed rate) than they are for plants with higher, more typical H_2S concentrations. To ensure that the cost effectiveness of controls at these facilities is similar to the cost effectiveness of controls at the other facilities covered by the standards, the standards have been revised to require less stringent emission reduction efficiencies for these plants.

(3) The proposed standards required determinations of achieved emission reduction efficiency over every 12-hour period. These 12-hour average efficiencies were then compared to a required efficiency (Z) determined quarterly. Several commenters, citing potential variability in sulfur feed rates over time, indicated that a requirement based on a determination made up to 3 months in the past may not remain achievable. To eliminate this problem, the standards have been changed to require daily determinations of required efficiency (Z). The standards also have been changed to require the determinations of achieved emission reduction efficiency over each 24-hour period instead of each 12-hour period. This change does not significantly diminish the accuracy of the determination but responds to comments indicating that some small remote plants may be unmanned for up to 12 hours each day.

(4) Based on an incremental cost-effectiveness analysis, monitoring requirements for facilities with design capacities less than 150 LT/D have been changed to allow less rigorous monitoring methods. Instead of continuously monitoring stack gas SO_2 concentrations, these facilities may calculate emission reduction efficiency on a daily basis based on measurements of inlet sulfur and recovered sulfur once every 24 hours.

(5) The requirement for maintaining the incinerator combustion zone temperature at 1000°F has been deleted. Instead, a site-specific temperature requirement, determined during the performance test, will be required for those facilities with stack monitors. This temperature must be sufficient to ensure that at least 98 percent of the sulfur in the stack gas will be in the form of SO_2. The standard also now allows plants the flexibility of monitoring both SO_2 and total reduced sulfur compounds in lieu of meeting the minimum temperature requirement.

In response to comments on the proposed standards pertaining to the economic impact analysis, a revised analysis was conducted using a different methodology and incorporating several updated assumptions. The new analysis used a discounted cash flow model (calculating the net present value of each model case over the timeframe of the analysis). Updated assumptions included: a variable price for gas (instead of the constant $4.80 per thousand cubic feet (MCF) used in the original analysis) ranging from $3.88/MCF in 1985 to $5.82/MCF in 1994; a 12-year plant life for facilities with sulfur feed rates <20 LT/D instead of a 20-year life; and a $77/LT value for sulfur credits for plants with sulfur feed rates >5 LT/D rather than the $100/LT value assumed in the previous analysis. Baseline sweetening costs were included in the new analysis. Of approximately 1,000 cases analyzed (different combinations of sulfur feed rate, H_2S-to-CO_2 ratios in the acid gas, and H_2S content in the sour gas), 27 could, if built, experience adverse economic impacts due to the NSPS. However, the cumulative probability of facilities with these particular combinations of gas characteristics being built in the future is only about 1 percent. Given this low probability, the conclusion of the revised analysis is that there will be no adverse impacts on plants likely to be built in the future. Thus, the standards are not expected to adversely affect incentives to develop new sour gas fields, and they are not expected to result in an increase in the price of natural gas.

1.2 SUMMARY OF IMPACTS OF PROMULGATED ACTION

1.2.1 Alternatives to the Promulgated Action

The regulatory alternatives are discussed in Chapter 6 of the background information document for the proposed standards (EPA-450/3-82-023a). These regulatory alternatives reflect the different levels of emission control that were analyzed in determining best demonstrated technology, considering costs, nonair quality health, and environmental and economic impacts for onshore natural gas processors. These alternatives remain the same.

1.2.2 Environmental Impacts of the Promulgated Action

The recommended standards would reduce atmospheric emissions of SO_2 from about 39 newly constructed sweetening facilities by about 62,500 megagrams per year (68,900 tons per year) in the fifth year of implementation. Implementation of the standards will not result in any adverse solid waste impact or water impact.

1.2.3 Energy and Economic Impacts of the Promulgated Action

Energy impacts resulting from the standard are discussed in Chapter 7 of the Volume I BID and have not changed significantly since proposal. The revised economic impact analysis, incorporating assumptions updated since proposal, indicates that no adverse economic impacts on projected facilities are expected to result from the standards. This revised analysis is discussed in Appendix A of this document.

1.2.4 Other Considerations

1.2.4.1 Irreversible and Irretrievable Commitment of Resources. The regulatory alternatives defined in Chapter 6 of the Volume I BID would not preclude the development of future control options nor would they curtail any beneficial use of resources. The alternatives do not involve short-term environmental gains at the expense of long-term environmental losses. The alternatives yield successively greater short- and long-term environmental benefits, with the alternative upon which the final standards are based providing the greatest benefits. Further, none of the alternatives result in the irreversible and irretrievable commitment of resources. No changes in these considerations have resulted since proposal of the standard.

1.2.4.2 Environmental and Energy Impacts of Delayed Standards. As discussed in Chapter 7 of the Volume I BID, delay in the standard would cause a similar delay in realizing the beneficial impacts associated with the standard. No changes in the potential effects of delaying the standard have occurred since proposal.

2.0 SUMMARY OF PUBLIC COMMENTS

This document includes responses to public comments on the proposed standards received in a total of thirty-one (31) letters and five (5) public hearing presentations. The public hearing was held on March 7, 1984. A list of the commenters, their affiliations, and the EPA docket numbers assigned to their correspondence is given in Table 2-1.

For the purpose of orderly presentation, the comments have been categorized under the following topics:

1. Need for Standards,
2. Applicability of the Standard,
3. Definitions,
4. Emission Control Technology,
5. Selection of Model Plants,
6. Economic Impact Analysis,
7. Cost-Effectiveness Analysis,
8. Small Plant Exemption,
9. Catalyst Life,
10. 1000°F Temperature Requirement,
11. Format of the Standard,
12. Monitoring and Performance Test Requirements,
13. Recordkeeping and Reporting Requirements,
14. Difference in State and NSPS Requirements, and
15. Miscellaneous Comments.

The comments, the issues they address, and responses to each comment are discussed in the following sections of this document.

2.1 NEED FOR STANDARDS

Comment: Several commenters (IV-F-1, IV-F-3, IV-F-5, IV-D-8, IV-D-10, IV-D-11, IV-D-13, IV-D-28, IV-D-29, and IV-D-30) stated that the proposed standards are unnecessary because the natural gas production

Table 2-1. LIST OF COMMENTERS ON PROPOSED STANDARDS FOR ONSHORE NATURAL GAS PROCESSING: SO_2 EMISSIONS

Docket item number[a]	Commenter and affiliation
IV-D-1	J. D. Reed Standard Oil Company (Indiana) 200 East Randolph Drive Chicago, Illinois 60601 Date: February 14, 1984
IV-D-2	Richard E. Grusnick Alabama Department of Environmental Management 1751 Federal Drive Montgomery, Alabama 36130 Date: February 14, 1984
IV-D-3	R. E. Cannon Gas Processors Association 1812 First Place Tulsa, Oklahoma 74103 Date: March 2, 1984
IV-D-4	J. D. Geiger Aminoil USA Post Office Box 94193 Houston, Texas 77292 Date: March 7, 1984
IV-D-5	Lyman Yarborough Amoco Production Company 16945 Northcase Drive Houston, Texas 77210 Date: March 3, 1984
IV-D-6	H. K. Holland, Jr. Mobil Oil Corporation 150 East 42nd Street New York, New York 10017 Date: March 2, 1984

[a] The docket number for this project is A-80-20A. Dockets are on file at EPA Headquarters in Washington, D.C. and at the Office of Air Quality Planning and Standards in Durham, North Carolina.

(continued)

Table 2-1. Continued

Docket item number[a]	Commenter and affiliation
IV-D-7	Robert P. Miller Michigan Department of Natural Resources Stevens T. Mason Building Box 30028 Lansing, Michigan 48909 Date: March 30, 1984
IV-D-8	Howard Reiquam El Paso Natural Gas Company Post Office Box 1492 El Paso, Texas 79978 Date: April 2, 1984
IV-D-9	John W. Graves Pennzoil Company Pennzoil Place Post Office Box 2967 Houston, Texas 77252-2967 Date: April 6, 1984
IV-D-10	Peter W. McCallum The Standard Oil Company Midland Building Cleveland, Ohio 44115-1098 Date: April 5, 1984
IV-D-11	B. L. Walters, Jr. Marathon Oil Company Findlay, Ohio 45840 Date: April 4, 1984
IV-D-12	Randy L. Pitre Cities Services Oil and Gas Corporation Box 3908 Tulsa, Oklahoma 74102 Date: April 6, 1984

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[a] The docket number for this project is A-80-20A. Dockets are on file at EPA Headquarters in Washington, D.C. and at the Office of Air Quality Planning and Standards in Durham, North Carolina.

(continued)

Table 2-1. Continued

Docket item number[a]	Commenter and affiliation
IV-D-13	Hugh B. Barton Exxon Company, USA Post Office Box 2180 Houston, Texas 77001 Date: April 12, 1984
IV-D-14	Howard Reiquam El Paso Natural Gas Company Post Office Box 1492 El Paso, Texas 79978 Date: April 23, 1984
IV-D-15	Steven F. Kurmas Michigan Consolidated Gas Company 500 Griswold Street Detroit, Michigan 48226 Date: April 25, 1984
IV-D-16	H. Schuyten Chevron USA, Incorporated 575 Market Street San Francisco, California 94120 Date: May 22, 1984
IV-D-17	Bill Stewart Texas Air Control Board 6330 Highway 290 East Austin, Texas 78723 Date: May 25, 1984
IV-D-18	J. P. Keehan Mobil Oil Corporation 150 East 42nd Street New York, New York 10017 Date: May 30, 1984
IV-D-19	R. E. Cannon Gas Processors Association 1812 First Place Tulsa, Oklahoma 74103 Date: June 1, 1984

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[a] The docket number for this project is A-80-20A. Dockets are on file at EPA Headquarters in Washington, D.C. and at the Office of Air Quality Planning and Standards in Durham, North Carolina.

(continued)

Table 2-1. Continued

Docket item number[a]	Commenter and affiliation
IV-D-20	J. Donald Annett Texaco USA 1050 17th Street, Northwest Suite 500 Washington, D.C. 20036 Date: June 5, 1984
IV-D-21	Jack G. Sevenson Rocky Mountain Oil and Gas Association, Incorporated 345 Petroleum Building Denver, Colorado 80202 Date: June 5, 1985
IV-D-22	Frank J. Duffy Northern Gas Products Company 2223 Dodge Street Omaha, Nebraska 68102 Date: June 5, 1984
IV-D-23	R. J. Cinq-Mars Cities Service Oil and Gas Corporation Box 300 Tulsa, Oklahoma 74102 Date: June 1, 1984
IV-D-24	A. G. Smith Shell Oil Company One Shell Plaza Post Office Box 4320 Houston, Texas 77210 Date: June 6, 1984
IV-D-25	J. D. Geiger Aminoil USA Post Office Box 94193 Houston, Texas 77292 Date: June 1, 1984

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[a] The docket number for this project is A-80-20A. Dockets are on file at EPA Headquarters in Washington, D.C. and at the Office of Air Quality Planning and Standards in Durham, North Carolina.

(continued)

Table 2-1. Continued

Docket item number[a]	Commenter and affiliation
IV-D-26	Howard Reiquam El Paso Natural Gas Company Post Office Box 1492 El Paso, Texas 79978 Date: June 4, 1984
IV-D-27	P. J. Early Amoco Production Company 200 East Randolph Drive Post Office Box 5340A Chicago, Illinois 60680 Date: June 5, 1984
IV-D-28	Lawrence J. Ogden Interstate Natural Gas Association of America 1660 L Street, Northwest Washington, D.C. 20036 Date: June 6, 1984
IV-D-29	John G. Blackburn, Jr. American Petroleum Institute 1220 L Street, Northwest Washington, D.C. 20005 Date: June 6, 1984
IV-D-30	J. J. Moon Phillips Petroleum Company Bartlesville, Oklahoma 74004 Date: June 5, 1984
IV-D-31	L. T. Reed Warren Petroleum Company Post Office Box 1589 Tulsa, Oklahoma 74102 Date: June 5, 1984

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[a] The docket number for this project is A-80-20A. Dockets are on file at EPA Headquarters in Washington, D.C. and at the Office of Air Quality Planning and Standards in Durham, North Carolina.

(continued)

Table 2-1. Concluded

Docket item number[a]	Commenter and affiliation
IV-F-1	R. L. Reed Gas Processors Association 1812 First Place Tulsa, Oklahoma 74103 Date: March 7, 1984
IV-F-2	Randy G. Abernathy Goar, Arrington and Associates, Incorporated Post Office Box 6947 Tyler, Texas 75711 Date: March 7, 1984
IV-F-3	Gary E. Reed Texas Oil and Gas Corporation Fidelity Union Tower Dallas, Texas 75201 Date: March 7, 1984
IV-F-4	Louis Roberts Texas Air Control Board 6330 Highway 290 East Austin, Texas 78723 Date: March 7, 1984
IV-F-5	C. R. Kreuz (On behalf of) American Petroleum Institute 150 East 42nd Street New York, New York 10017 Date: March 7, 1984

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[a] The docket number for this project is A-80-20A. Dockets are on file at EPA Headquarters in Washington, D.C. and at the Office of Air Quality Planning and Standards in Durham, North Carolina.

industry does not contribute significantly to nationwide SO_2 emissions. Commenters IV-F-5 and IV-D-13 cited an EPA document (National Air Pollutant Emission Estimates) as providing data indicating that in 1980 the natural gas production industry accounted for 3.6 percent of industrial SO_2 emissions and 0.4 percent of all anthropogenic SO_2 emissions.

Response: The crude oil and natural gas production industry is a significant source of SO_2 emissions. Sweetening units and sulfur recovery units are the primary contributors of the total SO_2 emissions from this source category. In the analysis supporting the proposed standard, the Agency estimated based on a projected growth of 44 new sweetening units and sulfur recovery units with a sulfur feed rate of 1.0 LT/D or more, that SO_2 emissions would increase by approximately 110,000 megagrams per year (121,000 tons per year) by the fifth year in the absence of these standards.* This estimate is based on detailed studies of individual natural gas processing units and the emission reduction currently required under State implementation plans (SIP). One hundred ten thousand Mg/year is a significant quantity of SO_2 to be emitted as air pollution.

The significance of SO_2 emissions from the crude oil and natural gas production industry is reflected in the Priority List, 40 CFR 60.16. The Priority List consists of categories of air pollution sources that, in EPA's judgment, cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Of the 59 major source categories on this list, the crude oil and natural gas production industry source category ranked 29th. Commenters have not presented any new information which would change the decision to list the crude oil and natural gas production industry on the Priority List.

It should be noted that because SO_2 emissions come from a large number of diverse source categories, many source categories contribute a relatively small percentage to the large overall total emissions. Even though natural gas processing plants may represent a small percentage of total emissions, the magnitude of emissions from natural gas processing plants is significant.

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*A revised analysis in support of the promulgated standard projects 39 affected facilities and an emissions increase in the fifth year of 76,600 Mg/yr in the absence of the standards.

Since the crude oil and natural gas production industry is on the Priority List as a significant contributor to air pollution under Section 111(f) of the Clean Air Act (The Act) as amended in 1977, standards of performance were required to be promulgated for those new sources within this source category for which the EPA can identify the best demonstrated technology (BDT) considering costs. The EPA has identified several alternative systems of control capable of achieving additional emission reduction at reasonable cost at natural gas processing plant sources. It is, therefore, reasonable for EPA to establish standards for these sources.

Comment: Several commenters (IV-F-1, IV-F-5, IV-D-8, IV-D-10, IV-D-13, IV-D-18, IV-D-19, IV-D-20, IV-D-22, IV-D-25, IV-D-26, IV-D-28, IV-D-29, and IV-D-30) stated that there is no need for the standards because SO_2 emissions from sweetening and sulfur recovery units are adequately controlled by other regulations, specifically prevention of significant deterioration (PSD) regulations and SIP requirements. Several States were cited as having existing regulations equivalent to at least Alternative II and often exceeding Alternative III. As a result, the standards are considered to be unnecessary and to needlessly cause an increase in natural gas production costs (IV-F-1).

Response: New source performance standards (NSPS) required by Section 111 play a unique role under the Clean Air Act. The main purpose of NSPS is to require new, modified, and reconstructed sources to reduce emissions to the level achievable by the best technological system of continuous emission reduction. Consideration must be given to the cost of achieving such emission reduction, any nonair quality health and environmental impacts, and energy requirements [Section 111(a)(1)]. Congress recognized that establishing such standards would minimize increases in air pollution from new sources, thereby improving air quality as the Nation's industrial base is replaced over the long term. The role of NSPS in achieving the goals set forth in the Act is distinct from that of other regulations.

The PSD requirements serve a different but complementary role to new source performance standards. The PSD requirements are designed to protect local air quality values and to ensure that air quality does not significantly deteriorate. The PSD requirements may vary according to air quality conditions in the specific area of the plant, whereas NSPS provide a uniform minimum requirement based on BDT for a particular emission source category, irrespective of local air quality conditions or values. The NSPS serve to establish the minimum requirements for new and mofified sources subject to PSD. At their discretion, States may elect to require greater emission reductions than would be achieved under NSPS in order to make more room for future industrial growth or to afford a higher level of air quality protection in a given area. In most instances, however, the level of control required under PSD does not exceed the level of control required under NSPS and, in fact, is established based on information obtained as a result of the development of NSPS.

The EPA estimates that these standards will reduce SO_2 emissions from the natural gas production industry by about 62,500 megagrams per year (68,900 tons per year) in the fifth year of implementation compared to existing SIP requirements. This represents a reduction in SO_2 emissions of 76 percent from SIP levels. The Agency considers such an emission reduction as significant and believes that standards that achieve such reductions are warranted.

In addition, many PSD determinations and SIP's governing SO_2 emissions do not address control of small plants. These plants constitute a significant proportion of SO_2 emissions. Based on projected baseline (SIP) control levels (1982 to 1987), emissions of SO_2 from onshore natural gas processing plants with sulfur feed rate capacities from less than 1 LT/D to 5 LT/D account for 25 percent of projected industry wide SO_2 emissions. Most of these emissions would be controlled by the NSPS.

Comment: The commenter (IV-D-20) stated that the proposed standards should be withdrawn because the Agency has overestimated the magnitude of SO_2 emissions from onshore natural gas processing plants, overestimated the impacts of SO_2 emissions from such sources on public health and welfare, overestimated the emissions reductions that would be accomplished by the standards, and underestimated the economic impact on the oil and gas production industry, especially in the case where small quantities of H_2S are being removed from gas streams and are being combusted. No specific data were supplied by the commenter to substantiate these statements.

Response: Because onshore natural gas processing plants are a subcategory of the Crude Oil and Natural Gas Production Industry source category, listed as 29th on the NSPS Priority List, the Act requires EPA to promulgate standards. The Priority List ranks major source categories according to criteria specified in Section 111(f) of the Act. One of these criteria is "the extent to which each pollutant endangers public health or welfare." Sulfur dioxide has been well established as a pollutant having adverse effects on health and welfare. There are National Primary and Secondary Ambient Air Quality Standards for SO_2. Also, SO_2 is recognized as a precursor to acid rain (Docket Entry IV-J-3).

As stated in the response to previous comments, the magnitude of emissions from natural gas processing plants is significant. Estimates of SO_2 emissions from these sources were based on data received from the industry. Nationwide SO_2 emissions from the existing industry are estimated to be 250,000 Mg/year.

The Agency's estimation of emissions reductions that would be accomplished by the standard represents a comparison between Regulatory Alternative III requirements and baseline emissions. The baseline values reflect typical SIP levels. The SO_2 emission reduction attributable to the standard has been estimated to be 62,500 Mg/yr (68,900 tons/yr) in the fifth year after promulgation.

For a discussion of economic impact estimations, the commenter is referred to Section 2.6 of this volume.

2.2 APPLICABILITY OF THE STANDARD

Several commenters requested clarification of the applicability of the standard.

Comment: Two commenters (IV-F-1 and IV-D-16) believed that much of the CO_2 from enhanced oil recovery plants would have to be sweetened before reinjection as a result of the proposed definition of "sweetening unit" and suggested a clarification such that the standards apply only to those sweetening units which release acid gas into the atmosphere.

Comment: The commenter (IV-D-18) requested that facilities whose primary purpose is to handle and/or cycle CO_2 for enhanced oil recovery be exempted from the standard, even though H_2S is associated with the CO_2. The commenter claimed that a CO_2 plant may be affected by the standard if the sulfur feed rate exceeds the minimum level, although all the sulfur-containing gas may be reinjected into a reservoir.

Comment: Three commenters (IV-D-19, IV-D-27, and IV-D-31) recommended exempting CO_2 and H_2S streams that are processed through a sweetening unit and are then injected for recovery of oil because sulfur compounds are not released to the atmosphere in that process. One of these commenters (IV-D-27) also suggested an exemption for these facilities when the acid gas stream is delivered to another company.

Response: The standard has been amended to clarify that affected facilities are those sweetening units (including sweetening units followed by sulfur recovery plants) that emit some or all of the acid gas stream to the atmosphere. An applicability provision has been added in §60.640(e) that reads, "The provisions of this subpart do not apply to sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere."

Comment: Another commenter (IV-D-2) requested clarification on the applicability of the standard as to whether the minimum plant size affected is measured in terms of sulfur available as H_2S or as sulfur.

Response: Paragraph 60.640(b) has been changed to clarify that the minimum plant size is measured in terms of sulfur, as intended in the proposed standard.

Comment: Two commenters (IV-F-4 and IV-D-17) requested clarification of the designation of affected facility as it applies to onshore plants processing natural gas produced offshore.

Response: Paragraph 60.640(c) has been revised to state that sweetening units and sulfur recovery units that process natural gas produced from either onshore or offshore wells are covered by the standards. Paragraph 60.640(c) now reads, "The provisions of this subpart are applicable to facilities located onshore which process natural gas produced from either onshore or offshore wells."

Comment: Two commenters (IV-D-13 and IV-D-18) requested a clarification of paragraph 60.640(c) as to whether the reference to "offshore" refers to the outercontinental shelf (OCS) or to facilities located on a platform in inland coastal marshes or bays.

Response: The standards were intended to exclude sweetening units and sulfur recovery units located on offshore platforms on the OCS. Facilities located on platforms in inland coastal marshes and bays are subject to the standards. An attempt was made by the Agency to obtain information regarding costs for sweetening units and sulfur recovery units constructed on platforms in inland coastal marshes and bays. The data obtained were not sufficient to determine what the costs would be for such units or whether they would be significantly different from the costs assumed in the Agency's cost analyses. One industry representative indicated that the construction of sweetening units or sulfur recovery units on rigs in inland coastal marshes and bays would be highly unlikely (Docket Entry IV-E-4). To clarify the definition of "onshore," §60.641 has been revised to read, "Onshore means all facilities except those that are located in the territorial seas or on the outercontinental shelf."

Comment: The commenter (IV-D-9) recommends that the iron oxide method (i.e., "iron sponge" method) for H_2S removal be explicitly exempted from the proposed standard. The commenter stated that these units are usually used to recover very small amounts of sulfur and are already exempted from regulations in the State of Texas.

Response: The Agency does not regard the use of a particular technology as an appropriate basis for exempting facilities from these standards. The EPA analyzed the cost effectiveness of various sulfur recovery technologies for a range of sulfur feed rates. For smaller feed rates, the 2-stage Recycle Selectox was used as a representative technology for the purpose of estimating the cost effectiveness of the proposed standards. The cost of using the iron oxide method of hydrogen sulfide removal was not specifically analyzed.

The commenter's suggestion was not accepted for two reasons. First, the EPA's analysis of cost effectiveness indicates that 2.0 long ton per day (LT/D) of sulfur feed rate is an appropriate cutoff regardless of the sulfur recovery technology used. Feed rate is a much more significant factor influencing cost effectiveness than the difference in control cost for various technologies. In any case, demonstrated technologies with acceptable costs are available for use in reducing SO_2 emissions from plants with sulfur feed rates of 2.0 LT/D or more.

Second, Section 111(b)(2) of the Act authorizes EPA to distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing standards. Excluding facilities based on size because of unreasonable cost impacts, as done in these standards, is an appropriate basis for excluding small facilities.

Under these standards, small plants (less than 2.0 LT/D sulfur feed rate) are exempt regardless of the sulfur recovery process used. If all or most plants below that size use the iron oxide method, then such plants will be exempt from the standards based on their low sulfur feed rate.

Comment: Three commenters (IV-D-13, IV-D-27, and IV-D-29) requested that a paragraph be added to §60.646 of the proposed standards to indicate that installation of equipment for process improvement (accomplished without capital expenditure) not be considered a modification. The commenter cited a similar section in 40 CFR 60.630(c), the proposed standards for equipment leaks of VOC from onshore natural gas processing plants.

Response: Under the General Provisions of 40 CFR Part 60, any physical or operational change to an existing facility which results in an increase in the emission rate of any pollutant may be considered a modification within the meaning of Section 111 of the Act. Such physical or operational changes constitute modifications subject to NSPS unless covered under one of the general exemptions of §60.14(e) or expressly exempted under the standards applicable to the source category.

The proposed VOC standards for onshore natural gas processing plants (49 FR 2636, January 20, 1984) included a specific exemption for the "addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure. . ." [§60.630(c)]. This special exemption was included because of the anticipated replacement of numerous valves, gaskets, and other small pieces of equipment for the purpose of process improvements. These changes are directly related to leaks of VOC and, therefore, could result in an emissions increase from the process unit, thereby causing the entire process unit to be subject to the standards under the modification rule. By including an express exemption for these small changes that can be accomplished, in most cases, without a capital expenditure, the Agency intended to clarify that such changes would not, by themselves, constitute modifications.

In the case of the SO_2 standards, the General Provisions already include exemption provisions that sufficiently address likely equipment changes related to SO_2 emissions. Section 60.14(e)(1) provides that maintenance, repair, and replacement which the Administrator determines to be routine for the source category shall not be considered modifications. Section 60.14(e)(2) provides that an increase in the production rate of an existing facility that can be accomplished without a capital expenditure also shall not be considered a modification subject to NSPS.

Because numerous small non-capital changes that would result in an emission rate increase are not anticipated with sweetening or sulfur recovery units, the Agency is not aware of any circumstances that warrant an exemption similar to that provided in the VOC standards. The general exemption provisions of paragraphs 60.14(e)(1) and (2) currently provide an adequate means for exempting changes involving small pieces of equipment. For this reason, the commenter's recommendations were not included in the SO_2 standards.

Comment: One commenter (IV-D-13) requested that the standard, if it is promulgated, be made effective (sic) 12 months after the final publication in the Federal Register to avoid uncertainties regarding plant construction after January 20, 1984. Another commenter (IV-D-18) recommended changing the standard's effective date to 180 days after the date of adoption.

Comment: The commenter (IV-D-29) recommended that the Administrator publish in the Federal Register an official notice of retraction of the January 20, 1984 effective date (sic) for purposes of the definition of a "new source." The commenter claimed that failure to do so would impose unnecessary burdens in industry because any planning or design work begun after the publication date must incorporate the elements of the proposed standard which have not yet become requirements. He further stated that Section 111(b)(1)(B) requires the Administrator to promulgate a standard within 90 days of publication of a proposal, and that review of comments can result in delays past the 90 day period. He claimed that the Agency had the authority to mitigate the inequity associated with any delay past 90 days necessary for reasoned decisionmaking.

Response: Proposal of the standards is legal notification that an owner or operator of an affected facility will be subject to the standards. Affected facilities are those for which construction, modification, or reconstruction is commenced on or after the applicability date, i.e., the date of proposal in the Federal Register. The Act [Section 111(a)(2)] clearly states the Congressional intent that the proposal date will be the applicability date. The applicability date should be distinguished from the effective date of the regulation, which is the date on which the standards become legally enforceable. Under Section 111(b)(1)(B) of the Act, the effective date is the date of promulgation (i.e., final publication in the Federal Register).

The proposal date is the applicability date unless the promulgated (or revised) standard is not based on and achievable by the same technology specified at proposal. This decision is consistent with the EPA's practice of applying NSPS to all sources built after proposal where the promulgated (or revised) standards are based on and achievable by the same technology as the proposed standards.

Section 111(a)(2) implements the basic Congressional objective of preventing new pollution problems and improving air quality as industry changes by requiring all new sources, built or modified after proposal, to use BDT in achieving emissions reductions. Congress recognized the existence of some uncertainty as to the final standards that this technology must meet [S. Rep. No. 91-1196, 91st Cong. 2d sess; Senate Bill, §113(b)(2)]. The passage of time between identification of BDT as the basis of a standard and the final specification of the performance required of that technology, therefore, is not relevant by itself. Under Sections 111(b)(1)(B) and 307(d)(10), an NSPS should be promulgated within 6 months of proposal. However, Congress did not intend that if promulgation took longer, the category of new sources should change, Commonwealth of Pennsylvania v. EPA, 618 F. 2d 991, 1000 (3rd Cir. 1980); 45 FR 8210, 8232 (February 6, 1980); United States v. City of Painesville, 644 F. 2d 1186 (6th Cir. 1981), cert. den. 102 S. cit. 392 (1981); 49 FR 18076 (April 26, 1984).

The basic conclusion of the Agency is that the applicability date should not change except as necessary to prevent unreasonable costs. Neither uncertainty as to whether the Agency will promulgate the standard, nor substantial delay in promulgating the standard justifies postponing the applicability date.

2.3 DEFINITIONS

Two commenters requested clarification of the definitions of certain terms in the preamble and the proposed regulation.

Comment: One commenter (IV-F-2) requested that a reference pressure and temperature be added to the proposed regulation to define "standard cubic foot" of gas.

Response: In accordance with the definition of "Standard Conditions" given in the General Provisions, standard temperature means 293K (68°F); standard pressure means 101.3 kilopascals (29.92 in. Hg). Because the definition is presented in the General Provisions, it is not necessary to repeat it in each subpart.

Comment: The commenter (IV-F-2) stated that the mole percent H_2S in the acid gas should be defined on a wet basis because in its actual state coming from the sweetening unit the acid gas is saturated with water, usually 5 to 10 mole percent H_2O.

Response: The mole percent H_2S in the acid gas from the sweetening unit was defined on a dry basis for two reasons. First, the mole percent H_2S data used in the analysis to yield the sulfur recovery efficiency equations were collected on a dry basis. Second, the Tutwiler method commonly used to determine the mole percent H_2S in the acid gas yields data on a dry basis. Consequently, the dry basis for the mole percent H_2S was retained in the standards to ensure consistency with the basis for the efficiency equations and with measurements obtained according to the Tutwiler method.

Comment: Four commenters (IV-D-13, IV-D-18, IV-D-27, and IV-D-29) stated that there was an inconsistency in the use of the term "1.0 long ton per day of hydrogen sulfide (H_2S) in the acid gas" in paragraphs 60.640(b), 60.641, and 60.647(c). One of the commenters suggested that the phrase be changed to "1.0 long ton per day of H_2S in the acid gas, expressed as sulfur."

Response: The standards were revised to incorporate the phrase "H_2S (in the acid gas) expressed as sulfur," in §§60.640, 60.641, and 60.647, per the commenters' suggestion.

Comment: The commenter (IV-D-13) suggested that the definition of "acid gas" be revised to clarify that acid gas means the outlet stream of a sweetening unit. The commenter recommended the following definition: "Acid gas means a stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit."

Response: The standards were revised in §60.641 to incorporate the definition of acid gas suggested by the commenter.

Comment: The commenter (IV-D-13) suggested that the definition of sulfur production rate be changed to the following: "Sulfur production rate means the rate of liquid sulfur (elemental sulfur with a molecular weight of 256) accumulation from the sulfur recovery unit."

Response: The commenter was contacted to ascertain the purpose of his comment. He indicated that the intent of the comment was to ensure consistency in measurement of sulfur production and theoretical recovery calculations and to distinguish between liquid sulfur, S_8 (molecular weight 256) and atomic sulfur, S (molecular weight 32).

All sulfur measurements will be made in terms of liquid sulfur (S_8) and the Agency does not think it is necessary to define sulfur in terms of its molecular weight. Therefore, the definition of sulfur production weight was not changed.

Comment: The commenter (IV-D-13) suggested that clarification of whether auxiliary or adjacent plant equipment is included in the terms "sulfur recovery unit" and "sweetening unit" might be desirable. The commenter noted that the scope of these definitions could have a significant impact on whether changes in such auxiliary or adjacent equipment would constitute modifications subject to the proposed standards. The commenter, however, expressed satisfaction with the definitions of "sulfur recovery unit" and "sweetening unit" as proposed, which the commenter understood to exclude equipment not essential to the sweetening or recovery process.

Response: All equipment that is essential to the gas sweetening or sulfur recovery process is part of the affected facility under these standards. For example, the definition of sweetening unit includes all essential components of the sweetening process such as the gas contactor or solvent absorber, solvent regeneration columns, pumps, coolers, and condensers. Auxiliary or adjacent equipment that is not an integral component of a sweetening unit or sulfur recovery unit is not considered part of the affected facility. Consequently, changes to such equipment would not constitute a modification that would bring an existing sweetening or sulfur recovery unit within the coverage of these standards.

Comment: The commenter (IV-D-29) stated that a definition for "capital expenditure" should be added to the standard. The commenter stated that 40 CFR Part 60 defines capital expenditure as a fixed percentage of the "cost basis" as defined by the IRS and stated that the value is used to establish the cost threshold of a process improvement modification that would cause a plant to come under the NSPS. He claimed that many old gas plants were constructed at costs below today's cost and the "cost basis" is therefore low. He also claimed that IRS Publication 543 establishes the fixed percentage repair allowance for gas plants at 4.5 percent, which is low compared to that for refinery equipment (7 percent) and onshore exploration equipment (10 percent). He claimed that a low "cost basis" and low repair allowance percentage would discourage process improvement and perpetuate less efficient operations. He recommends adding a definition that raises the fixed percentage repair allowance to 10 percent.

Response: The EPA acknowledges that costs have increased over time due to inflation and that the facility's "cost basis" does not reflect today's costs. Also, the older a plant is, the more likely it is that a change causing an emission rate increase and involving a production rate increase could also involve a capital expenditure (the three conditions that would have to be met in the commenter's example before the facility would come under the NSPS as a modification). One purpose of the modification provision is to prevent continual changes to old high-emitting facilities that serve to prolong the life of the old facility while circumventing emission control requirements. Thus, it is appropriate that changes to old facilities (those with a low cost basis relative to today's cost) which increase the facilities' emission rates should result in bringing the facilities under the NSPS.

However, it should be noted that old facilities that are instituting process improvements need not come under the modification provision. An owner or operator can avoid coming under the modification provision by making process improvements that do not, in themselves, cause an emission rate increase or that do not result in an emission rate increase from the facility because offsetting changes are made elsewhere in the affected facility. It is only when there is an emission rate increase in addition to a production rate increase that the captial expenditure criterion is applicable in determining whether there is a modification, as defined in §60.14 of the General Provisions. For this reason, the Administrator does not believe that using the capital expenditure criterion, as defined in the General Provisions (§60.2), necessarily discourages process improvements or perpetuates less efficient operations.

In regard to the repair allowance percentage of 4.5 for natural gas processing plants, the 4.5 percent Annual Asset Guideline Repair Allowance Percentage (AAGRAP) for a natural gas processing plant is established by the IRS, and its applicability to NSPS is established in the General Provisions. Because the AAGRAP is determined by the IRS to be an appropriate depreciation parameter for determining tax liability, EPA considers it an appropriate basis for determining the maximum amount a facility can reinvest for process maintenance and/or improvement purposes without having made a "capital expenditure." The EPA recognizes that other industries use different AAGRAP percentages. The AAGRAP values are industry-specific based on the type of operations performed by the industry and the expected repair expenses that the industry is likely to incur. As such, the AAGRAP would require adjustment by the IRS and not by EPA.

Comment: The commenter (IV-D-29) responded to a request made at the public hearing (March 7, 1984, Docket Entry IV-F-6) for a definition of small remote plants. The commenter stated that small remote plants should be defined as those at which an operator can demonstrate that skilled labor pools are not readily available.

Response: The Agency has extensively evaluated the potential impacts of these standards on small plants and has concluded that cost, economic, and other impacts of these requirements are reasonable for small plants processing at least 2 LT/D of sulfur. (Plants with sulfur feed rates below 2 LT/D are not subject to these standards due to cost-effectiveness considerations.)

The remote location of some plants has been addressed in the revision to the standards that provides for sulfur measurements every 24 hours instead of every 12 hours, as required at proposal. This revision addresses the issue of remote plants which are unattended for 12 hours of an operating day.

Because the provisions for small plants are applicable to all small plants, irrespective of location, there is no need for a definition of small remote plants. As a result, the definition suggested by the commenter was not included in the regulation.

Comment: The commenter (IV-D-27) stated that metric units are used in paragraph 60.641 and that the desired results could be obtained with equal accuracy with any consistent units. He recommended that equivalent calculations with any set of units be permitted.

Response: For consistency and clarity, metric units are used throughout the standards, but calculations can be made in English units and converted into metric units.

Comment: The commenter (IV-D-29) suggested adding a new definition to §60.641 stating that "'process improvement' means routine changes made for safety and occupational health requirements, energy savings, better utility, ease of maintenance and operation, correction of design deficiencies, bottleneck removal, changing product requirements, or environmental control."

Response: This comment is related to one made by commenter IV-D-19 recommending that installation of equipment for process improvement purposes not be considered a modification. The term "process improvement" does not appear in the regulation. Since the suggestion made in comment IV-D-19 was not accepted, there is no need for a definition of the term "process improvement" to be incorporated into the standards.

2.4 EMISSION CONTROL TECHNOLOGY

Comment: One commenter (IV-F-2) stated that Table 1 on page 2660 of the preamble to the proposed standards might be interpreted to mean that EPA is not recommending 2-stage or 3-stage Recycle Selectox units for sulfur feed rates greater than 5 LT/D. The commenter stated that 2-stage and 3-stage Recycle Selectox units can be used for plants with sulfur feed rates of greater than 5 LT/D.

Response: Table 1 in the proposed standard shows model plant and control technology combinations for each regulatory alternative for the purpose of estimating impacts of each alternative standard. The table was not intended to be a recommendation on the best sulfur recovery process for various sulfur feed rates. The selection of control technologies for each regulatory alternative was based on the demonstrated control technology that has the highest recovery rate within the range of incremental cost effectiveness established for that particular regulatory alternative. Based on this criterion, Recycle Selectox 2-stage and 3-stage sulfur recovery units were selected as representative technologies for Regulatory Alternatives III to V for sulfur feed rates below 5 LT/D. Above that feed rate, other technologies were identified as having the greatest recovery efficiency within the ranges of incremental cost effectiveness established. The selection of other technologies for units with sulfur feed rates above 5 LT/D does not mean that Recycle Selectox units are not suitable for these larger feed rates.

Comment: One commenter (IV-F-2) questioned the accuracy of the sulfur recovery values stated in the proposed standards for 2-stage and 3-stage Claus units. The commenter believed the efficiencies stated in the proposed standards were too high and cited efficiencies from case studies in Appendix E of the Volume I BID as support. Specifically, the commenter noted that the proposed standards cited a 93.0 percent recovery for 2-stage Claus units with an inlet concentration of 12.5 mole percent H_2S whereas Table 6-11 in Appendix E refers to an average recovery of 91.3 percent. The commenter stated that recoveries for 2-stage Claus units with an inlet gas concentration of 12.5 mole percent H_2S should be

90 to 92 percent. The commenter also noted that the same table indicates an average recovery of 93.93 percent for a 3-stage Claus unit under the same conditions, whereas the proposed standards refer to a 94.7 percent recovery.

Response: There is no discrepancy between the efficiencies referred to by the commenter and cited by the Agency in the proposed standards. The recovery percentage of 93.0 percent for 2-stage Claus units referred to in the proposed standards is a start-of-run efficiency. The commenter's reference to 90 to 92 percent as the proper efficiency for 2-stage Claus units coincides with the Agency's average-of-run efficiency of 91.3 percent cited in Chapter 4 of the BID. The end-of-run efficiency for these units was determined to be 89.6 percent and the average-of-run efficiency to be 91.3 (the average of 93.0 and 89.6 percent).

Similarly, the recovery percentage of 94.7 for 3-stage Claus units with 12.5 mole percent H_2S represents a start-of-run efficiency. The 93.93 percent recovery referred to by the commenter represents an average-of-run efficiency.

Comment: The commenter (IV-F-2) added that a Claus unit cannot be operated with an acid gas feed of only 12.5 mole percent H_2S without employing some special method of sustaining combustion, such as acid gas feed preheating, oxygen injection, or recycle of product sulfur. The commenter said that these methods are energy intensive, require substantial capital investment, and are difficult to maintain. The commenter stated that 30 to 35 mole percent H_2S was required, as a minimum, to sustain combustion. Finally, the commenter questioned the practicality of using 2-stage or 3-stage Claus units to recover sulfur from systems with acid gas feed rates less than 20 to 25 mole percent H_2S.

Response: The Agency understands that for acid gas streams with H_2S concentrations below about 50 mole percent, the conventional straight-through Claus process experiences operating limitations, and that process modifications incorporating split-flow configuration, preheating of acid gas and air, and/or recycling of sulfur may be required. As discussed in the Volume I BID, split-flow design is used for acid gas stream with about 20 to 50 percent H_2S, preheated feed is used in the 10 to 25 percent H_2S range, and sulfur recycling (i.e., the "sulfur burning process") is used below 10 percent H_2S. Each of these supplemental technologies for the Claus process has been employed in the natural gas processing industry.

In its analysis of the costs of Claus units, EPA included the cost of energy consumption and capital costs of model plants employing these supplemental technologies to treat lean gas streams. For example, the Claus process evaluated for the 12.5 mole percent H_2S case referred to by the commenter was a split-flow configuration with preheated feed streams. Both the energy costs and the capital costs for a preheated feed stream were included for this case. Based on this analysis of Claus process costs, the Agency concluded that the total cost of Claus units for 12.5 mole percent H_2S is acceptable and that such units should be considered as one of several demonstrated technologies. The EPA acknowledges the applicability of the Recycle Selectox technology to leaner acid gas streams. For these leaner feed streams, Recycle Selectox recovery units are considered to be comparable in overall performance and cost to Claus units.

Comment: The same commenter (IV-F-2) recommended adding BSR/Selectox to the list of candidates for BDT, based on actual operating experience for a unit in West Germany, overall sulfur recovery efficiency, and operating costs. The commenter stated that recoveries of 99 percent and 99.6 percent can be reached with BSR/Selectox and BSR/Selectox followed by a final Claus stage, respectively, instead of the 97 percent and 98 percent recoveries given in the Volume I BID.

Response: In developing these standards, the Agency evaluated the performance of the BSR/Selectox tail gas process. Based on a review of data from the only industrial BSR/Selectox unit known to EPA, the statements made by the commenter appear supportable. This new process appears to be a reliable tail gas cleanup process capable of an overall sulfur recovery of 97.84 to 98.49 percent (average-of-run) at a reasonable cost. This compares to start-of-run efficiencies of 99 and 99.6 percent cited by the commenter. The BSR/Selectox process is discussed in detail in Chapter 4 of the Volume I BID.

Owners or operators are free to select any technology that will meet the standards applicable to their plant. The standards are based on the performance capabilities of the best demonstrated technology, considering cost, nonair quality health, and enviromental and energy considerations. However, the standards neither require nor preclude the use of any specific technology or process. There are a number of tail gas cleanup technologies, including the BSR/Selectox process, available for use in complying with these standards.

Comment: The commenter (IV-F-3) stated that the technical feasibility of sulfur recovery for plants with sulfur feeds less than 3 LT/D is in question.

Response: Before proposing the cutoff, the Agency investigated through the process designer and the Selectox catalyst manufacturer the capabilities of the Recycle Selectox process. The key to successful operation of small sulfur plants employing the Claus reaction ($2\ H_2S + SO_2 \longrightarrow 3S + 2\ H_2S$) is the maintenance of the 2 to 1 ratio of H_2S to SO_2. For this reason, particular attention was paid to the capabilities and limitations of the Selectox catalyst used in the Recycle Selectox process to oxidize H_2S to SO_2. The catalyst manufacturer provided information indicating that the catalyst effectively achieves 2 to 1 ratio irrespective of the amount of sulfur available in the acid gas stream. The technology has worked well at larger plants and there is no reason why it should not work at smaller plants because catalyst performance and the ratio of H_2S to SO_2 do not depend on sulfur feed rate. On this basis, the Agency concluded that sulfur recovery technologies are technically feasible for plants with sulfur feeds less than 3 LT/D.

Comment: Two commenters (IV-D-12 and IV-D-29) claimed that sulfur recovery technology is not currently available which can adequately handle the daily production rate fluctuations typically experienced at small facilities. The commenters further stated that production rates are often controlled by regulatory agencies and pipeline transmission companies and that those factors cause extensive fluctuations in production rates, especially when just a few small wells are involved. Other limiting factors mentioned were versatility of design for fluctuating flow rates and varying H_2S/CO_2 ratios and shutdown of wells for repair and service. Commenter IV-D-12 provided an analysis of best available control technology (BACT) for a sulfur recovery unit for a two-well operation. The conclusion reached in that analysis was that flaring was the BACT for that operation.

Comment: Another commenter (IV-D-25) stated that the feed to a natural gas plant varies constantly because producers are constantly shutting in or reworking wells, and that for a small sulfur recovery unit (15 LT/D or less) the fluctuation of the inlet stream has a significant effect on efficiency of the unit. The commenter claimed that a sulfur recovery unit can still operate when the acid gas volume has been reduced by two-thirds, but the efficiency decreases significantly and the unit requires constant attention by the operator to maintain operation.

Comment: The commenter (IV-D-28) claimed that the technology for recovering sulfur from acid gas streams with low H_2S concentrations is not well proven, and therefore, this raises serious questions as to sulfur recovery efficiency, capital investment, and operating costs associated with such plants.

Response: The Agency conducted an extensive review of available sulfur recovery technologies prior to proposal. The Agency concluded that demonstrated technologies exist that are technically and economically feasible for use at facilities with greater than or equal to 1 LT/D capacity. Specifically, for small plants (about 1.0 to 5.0 LT/D), the 2-stage Recycle Selectox technology was determined to be applicable. The Recycle Selectox process has been employed on acid gas streams as lean as 2 percent H_2S, and a start-of-run recovery efficiency of 80.68 percent has been reported (Table H-6, BID). On this basis, demonstrated technologies are considered to be available for small plants and extremely lean acid gas streams. Further, the Recycle Selectox process with standard instrumentation can meet required recovery efficiencies when operating at one-third or less of design capacity. With dual instrumentation and control valves, at an added cost of 2 to 5 percent of the total plant cost, efficiencies can be maintained at levels as low as 10 to 20 percent of capacity (Reference Docket

Entries II-D-58 and IV-E-1). This capability allows sufficient process control to accommodate the feed rate fluctuations of typical small sulfur recovery plants, which generally do not vary more than 100 to 200 percent.

Capital investment and operating costs were provided by the Ralph M. Parsons Company and incorporate the normal contingencies used in costing. The Agency used standard industry practices for costing techniques.

Comment: The commenter (IV-D-7) suggested that proven technologies such as single-stage Claus units and caustic scrubbers be included as BDT in addition to the technologies considered in the proposed standard. The commenter cited sulfur recovery efficiencies of up to 85 percent for a single-stage Claus unit; greater than 95 percent for 2-stage countercurrent caustic scrubbers (91 to 94 percent normal operating efficiency); and greater than 85 percent for a single-stage caustic scrubber.

Response: The Agency acknowledges that single-stage Claus units and caustic scrubbers are proven sulfur recovery technologies that are available for use in meeting these standards. Single-stage Claus units were not selected as BDT because their sulfur recovery efficiencies are generally lower than other demonstrated technologies. Two-stage Claus units are capable of attaining recovery efficiencies between 93.0 percent (with a 12.5 percent H_2S concentration) and 96.3 percent (with an 80 percent H_2S concentration). A 3-stage Claus unit increases sulfur recovery to between about 94.7 percent (with a 12.5 percent H_2S concentration) and 97.3 percent (with an 80 percent H_2S concentration). These efficiencies compare to recovery efficiencies of 85 percent cited by the commenter for single-stage Claus units. Cost information provided by the commenter and in subsequent discussions with the Ralph M. Parsons Company (Docket Entry IV-B-8) indicate that the single-stage Claus unit costs approximately 10 percent less than the units designated as representative of BDT for comparable plant sizes.

During the development of the standards, the Agency had little information on the application of caustic scrubbers to sulfur recovery in the gas processing industry. For this reason, this technology was not fully evaluated. Data provided by the commenter and in subsequent preliminary investigations by the Agency (Docket Entry IV-B-8) indicate that the technology scrubs H_2S from the sour or acid gas streams with an aqueous caustic solution and the sulfur is removed from the process in the form of sodium hydrosulfide in the spent caustic solution. The economic success of the technology appears to be dependent upon the ability of operators to sell the spent absorbent and thereby recoup operating expenses (i.e., cost of caustic) and avoid disposal costs. The facilities known to the Agency reportedly use railroad tank cars to transport their spent absorbent to a paper mill where the absorbent is used to make up chemicals for the kraft pulping process.

The technologies recommended by the commenter could be used to meet these standards provided they achieve the required emission reduction efficiency. The use of single-stage Claus units or caustic scrubbers is not precluded by these standards, nor is any specific technology required to be used.

Comment: The commenter (IV-D-7) recommended investigation of two new control technologies, the LoCat_{TM} and Slurrisweet_{TM} processes. According to the commenter, the LoCat_{TM} process is essentially 100 percent efficient in sulfur removal and can be used to replace an amine sweetening unit or as a tail gas unit. Two LoCat_{TM} facilities reportedly have been proposed for construction in Michigan. The commenter reported that Slurrisweet_{TM} is limited to use on gas streams with relatively low H_2S concentrations, but is suited for streams previously handled by small or medium sized amine plants. Three Slurrisweet_{TM} facilities have been permitted, one of which is operating and reportedly performing well.

Response: As the standards were developed, the Agency reviewed the LoCat_{TM} and Slurrisweet_{TM} processes and their applicability for sulfur removal. At that time, concrete data were not available to evaluate the effectiveness, cost, and applicability of the two new technologies. Data provided by the commenter indicate that the two technologies may achieve sulfur recoveries comparable to or greater than other technologies at a reasonable cost, but only limited data exist with which to evaluate the performance record of the processes.

Comment: The commenter (IV-D-27) suggested that provisions be made in the standards to allow for decreases in the required recovery efficiency to 85 percent of the original requirements as throughput at a gas plant declines. He stated that declines in throughput for plants are inevitable, although timing of the decline may be delayed if new sources of gas are found. According to the commenter, plants experience problems achieving design efficiency when throughputs are below 50 percent of design; problems in achieving design efficiency become acute at 20 to 30 percent of design capacity. At 20 to 30 percent of capacity, the volume to surface area ratios degrade, control devices are oversized, and blowers must be turned down to inefficient values.

Comment: The commenter (IV-D-18) recommended that facilities operating at less than 50 percent of design capacity be exempt from the sulfur emission reduction efficiency requirements of §60.642.

The commenter also stated that natural gas processing facilities handle varying quantities of gas with different compositions over a period of time. Because of these fluctuations, the commenter recommended that compliance with the standard not be required if the composition of the gas or throughput changes are beyond the control of the owner or operator and such changes cannot be reasonably accommodated by the existing equipment.

Comment: The commenter (IV-D-29) suggested that plants operating at less than 50 percent of design capacity and at less than 20 LT/D throughput be exempted from the standards because of engineering problems that occur when plants operate at less than 50 percent of capacity. The commenter provided a case history of a 3-stage Claus plant designed with a 27 LT/D capacity. He stated that the capacity was based on limited production testing of shut-in gas wells that were expected to have relatively high H_2S concentration. The various gas lines supplying the plant contained 25 to 25,000 ppm H_2S and contained both sweet and sour gas. The commenter reported that the plant start-up was unsuccessful because the H_2S concentration and flow rates at the plant inlet would not sustain the thermodynamic requirements of the Claus catalyst bed regeneration process. About $275,000 was spent to downsize the plant to 15.6 LT/D. The plant started up processing seven sour gas streams that could deliver 11.35 LT/D of sulfur. One well comprised 3.77 LT/D of this total. Future connections are projected to supply 2.8 LT/D of sulfur. Continuous operation of at least one of the three major H_2S producing wells is considered critical to a turned down operation of the plant at 7 LT/D. He reported that further turndown would require another modification of the plant.

Comment: The commenter (IV-D-29) claimed that the economic structure on which the standard is based is in error because the difficulty of maintaining stable operation when the plant is operating at less than 50 percent of capacity is not considered. The commenter stated that operation at less than 50 percent of design capacity is a common occurrence as aging gas fields decline in production or in new fields where production has not reached peak levels. The commenter stated that during such times, equipment is oversized for throughput and the reactions that should take place are not complete. He further stated that these problems are beyond the control of the plant operator unless the plant is designed as a multitrain plant so that operation may be discontinued in stages as field gas production declines. He stated that the concept of multitrain design was not discussed in the Volume I BID or preamble. The commenter claimed that the standard would force operators to use the multitrain design to comply with sulfur recovery efficiencies.

Response: The required recovery efficiency, "Z," is based on the sulfur feed rate and H_2S concentration in the acid gas stream. Because the required recovery efficiency is a function of these factors, as the sulfur feed rate or H_2S concentration decreases, the recovery efficiency also decreases. Thus, the recovery efficiency equation at least partially accommodates declines in gas throughput.

In response to these and other similar comments, the Agency discussed the effect of decreased throughput on recovery efficiency with Ralph M. Parsons Company, an engineer design firm with expertise in sulfur recovery facilities (Docket Entry II-D-58 and IV-E-1). Information received from this firm indicates that a three-to-one turndown is attainable with standard instrumentation. A five-to-one or even seven-to-one turndown can be attained with additional instrumentation (e.g., dual control valves, dual metering, dual transmitters). Further, plants operated within their design operating ranges will achieve the design recovery efficiency regardless of capacity utilization. Based on these discussions, the Agency concluded that recovery efficiencies are not adversely affected by decreases in throughput to levels well below design capacity. As long as the proper H_2S to SO_2 ratio is maintained, design recovery efficiencies will not decline. The H_2S/SO_2 ratio can be maintained during periods of low throughput by modifying the supply of process air to the combustion zone. With the maintenance of an appropriate flow rate of the process air stream relative to the acid gas stream, stoichiometric concentrations of H_2S and SO_2 are attained and sulfur recovery efficiencies are maximized.

The installed costs of instruments vary from about 5 percent to 10 percent of the total plant costs. These instruments will usually allow good operation down to 33 percent of plant design rate. In order to allow operation down to 20 percent of the plant design rate, an additional instrumentation cost of 2 to 5 percent of the total plant cost can be expected (Docket Entry IV-E-1).

Based on the information received from the Parsons firm, it is apparent that proper instrumentation is the key factor in maintaining appropriate recovery efficiencies during periods of decreased throughput. The costs associated with this instrumentation (i.e., 5 to 10 percent of total plant costs) appear to be within the range of the commenter's expenditures for turndown modification.

Given the availability of technology and instrumentation to accommodate load changes, turndown within the design range should not affect the facilities' ability to achieve the required efficiency. The Agency concludes that facilities experiencing such fluctuations are expected to meet the requirements of the standards.

It should also be noted that plants with sulfur feed rates ≤5 LT/D are required to meet the lower end of the range of efficiency achievable by BDT for facilities of this size. This requirement accommodates potential process operating difficulties that may occur in small plants.

2.5 SELECTION OF MODEL PLANTS

Comment: One commenter (IV-F-4) questioned the assignment of 15 of the total 21 model plants as plants with capacities not greater than 5 LT/D. In his opinion, a more appropriate distribution would include a higher proportion of larger plants.

Response: The distribution of model plants selected was not intended to mirror the distribution of existing or future plants, but rather to facilitate the evaluation of various regulatory alternatives. The distribution of model plants included plants with capacities of less than 5 to more than 1,000 LT/D. Because potential adverse cost impacts are more likely for plants of less than 5 LT/D capacity (i.e., small plants), additional model plant cases in the small size range out of a total of 21 model plants allowed more thorough evaluation of small plant cost impacts.

Comment: The commenter (IV-D-13) questioned the use of 1982 production data as a basis for projecting the distribution of H_2S concentrations in future sour gas discoveries and the sizes of new facilities. The commenter claimed that as shallow reserves are depleted, new wells will be drilled deeper and that gas in those wells would be likely to have higher H_2S concentrations. In addition, the commenter stated that future plants will also likely be larger sized plants, even greater than 1,000 LT/D, because the new plants would have to be larger to be economically feasible. The commenter requested that these ideas be incorporated into development of the standards and stated that these trends indicate that only larger plants should be subject to the proposed standards.

Response: The Agency is aware of the trend toward development of deeper, more sour wells through discussions with industry representatives (Reference Docket Entry II-E-22). The trend toward higher H_2S concentrations has been quantified based on the limited amount of available data (see BID, Table 9-22) and considered in projecting the numbers of facilities to be constructed. However, quantification of this trend with respect to the size distribution of future facilities is not possible because there are insufficient data available on how H_2S concentration affects plant size. For this reason, the trend toward deeper, more sour wells could not be incorporated in the approach to projecting sizes of facilities to be affected by the standards. As the commenter suggests, the facility projections may overpredict the number of small plants and underpredict the number of large plants. Even if this is true, the trend would not adversely affect the conclusions of the cost and economic impact analyses.

Because economics of scale are possible with larger plants, they incur proportionately smaller cost impacts. Similarly, larger plants are less likely to incur adverse economic impacts. These facts show that the approach taken in projecting sizes of affected facilities probably overpredicts any potential adverse cost and economic impacts that could result from the standards.

Regarding the commenter's conclusion that only larger plants should be subject to the standards because of this trend toward larger plants, the standards are written to address the complete range of sizes that may be constructed. Whether or not facilities of a particular size actually are constructed cannot be predicted with certainty. The standards should and will require application of BDT for any size plants for which controls can be employed with acceptable economic impacts and cost effectiveness.

2.6 ECONOMIC IMPACT ANALYSIS

Comment: The commenter (IV-F-1) questioned the conclusion drawn in the economic impact analysis (Chapter 9, BID) that no plant closings are predicted under Regulatory Alternatives I through IV. This comment is based on alleged errors made by EPA in calculating the real cost of capital (BID, Section 9.2.1.1, pg. 9-60), and estimation of gas sales revenues (BID, Table 9-28, pg. 9-62). Specifically, the cost of capital was given as 0.019 (derived by the formula 1-discount rate/inflation rate); the value, using EPA's discount rate and inflation rate, would be -0.019. The commenter stated that since this incorrect cost of capital was used to calculate annualized costs, those costs are in error.

Secondly, the commenter stated that the use of an H_2S/CO_2 ratio of 12.5/87.5 percent in the economic analysis for model plants with less than 5 LT/D capacity overstates estimated revenues from gas sales and results in inaccurate emission control costs per MCF of sales gas. The commenter believed that ultimately these differences would indicate an increased potential for plant closings.

Response: The commenter is correct in noting that an error was made in the BID, Chapter 9, Section 9.2.1.1, page 9-60. The error was not in the calculation of the real cost of capital but in the presentation of the equation. The equation should read:

Real cost of capital = (1 + discount rate)/(1 + inflation rate) - 1.

The assumed discount rate was 10 percent and the inflation rate was 8 percent, therefore, the real cost of capital was .019, and that cost was used to calculate annualized costs.

Based on new information provided by the Gas Processors Association survey (August 1983) (see Docket Entry II-D-59), the economic impacts of the proposed NSPS have been reanalyzed. In the current analysis, a real interest rate or real industry cost of capital of 6 percent is used. This is calculated assuming a nominal interest rate of 11 percent (based on the current prime rate) and an inflation rate of 5 percent. In comparison to the 2 percent cost of capital used in the previous economic analysis, the current analysis assumes a much higher cost of capital reflecting the greater risk inherent in investments in the oil and gas industry.

In regard to the commenter's concern over the use of a 12.5/87.5 acid gas ratio for less than 5 LT/D model plants in estimating revenues from sales gas, the appropriateness of the acid gas ratio assumption must be considered in light of the assumed H_2S concentration in the sour natural gas and the range of model plant sizes (i.e., LT/D sulfur feed) to which the assumptions apply. The economic analysis considered H_2S concentrations in the sour gas ranging from 0.5 to 20 percent, model plant sizes ranging from 0.1 to 1,000 LT/D sulfur feed rate, and a single acid gas ratio of 12.5/87.5. The 12.5/87.5 acid gas ratio assumption is appropriate given that it applies to the entire range of H_2S concentrations in the sour gas and model plant sizes considered in the original analysis. However, as the commenter points out, acid gas ratios less than 12.5/87.5 are more frequently encountered in the less than 5 LT/D plants. Also, the percent H_2S in the sour gas for plants less than 5 LT/D more commonly is in the 0.1 to 0.5 percent range, rather than the 0.5 to 20 percent range considered in the original analysis.

Since proposal, an expanded economic analysis has been conducted (see Appendix A) that addresses the commenter's concern. In this expanded analysis, acid gas ratios of 2/98, 5/95, 12.5/87.5, 20/80, 50/50, and 80/20 and H_2S concentrations in the sour gas ranging from 0.1 to 9 percent were evaluated for plants in the less than 5 LT/D size range. Revenues from sweet gas sales for cases evaluated in the revised analysis cover the complete range that can reasonably be expected at small facilities. However, contrary to the concern raised by the commenter, the revised analysis does not identify adverse economic impacts (i.e., plant closings) on facilities expected to be constructed in the future.

Comment: Commenter IV-F-5 cited the potential for adverse economic impacts on nonmajor operators. He referenced an Oil and Gas Journal (July 18, 1983, pg. 89) report which stated that nonmajor operators account for 53 percent of all gas plants.

Response: The commenter has not provided any data on adverse economic impacts for nonmajor operators. The revised economic impact analysis conducted by the Agency indicates that Regulatory Alternative III, upon which the standards are based, will not force the cancellation or postponement of construction of projected onshore gas processing facilities. Consequently, shifts in output levels would be expected to be very slight and would not encourage higher gas prices, or any other disruption of the natural gas processing industry. Of the approximately 1,000 cases analyzed, 24 cases showed adverse economic impacts due to the NSPS (see Appendix A). However, the cumulative probability of facilities with the combinations of gas characteristics (represented by these 27 cases) being built in the near future is only about 1 percent. For this reason, the Agency believes that there will be no adverse economic impacts as a result of the NSPS.

Comment: The commenter (IV-D-8) stated that, based on operating experience at his facilities during 1978 through 1983, sulfur recovery facilities have operated at approximately 34 percent of capacity. The commenter stated that these plants once operated at 100 percent capacity, but all plants eventually experience such a decline as a function of field life. His concern is that the cost analysis performed by EPA on the model plants assumed 100 percent operating capacity and that this may affect the conclusions of the analysis. In subsequent discussions with the commenter (Reference Docket Entry IV-D-14), the commenter stated his concern that the entire economic analysis should take into account the fact that despite the decline in volumes, producers try to maximize production and as producing fields age, production declines.

Response: The commenter's concern about production decline as it relates to the cost analysis is addressed in Section 2.7. His concern about production decline as it relates to the economic analysis has been considered in a revised analysis presented in Appendix A. The revised analysis assumes that capacity utilization averages 75 percent over the life of the facility. (Selection of this factor is discussed in Section 2.7.) The amount of sweet gas and sulfur for sale are each calculated based on 75 percent capacity utilization. As the results of the revised economic impact analysis show, even when production declines are taken into consideration, the NSPS does not impose adverse economic impacts on plants likely to be built in the future. The probabilities of different size plants with different gas characteristics being built in the future were calculated. These probabilities were based on historical size and gas characteristic data. The potential economic impacts on each of these cases were estimated. Out of the approximately

1,000 cases examined, 27 showed significant adverse impacts due to the NSPS. However, the cumulative probability of a facility with characteristics similar to any of these cases being constructed during the next 10 years is only about 1 percent. Therefore, EPA's conclusion based on the economic impact analysis is that the NSPS will not impose unreasonable economic impacts on any plants likely to be built in the future.

Comment: The commenter (IV-D-19) states the combined effects of the assumptions used in the economic impact analysis (Chapter 9, BID) lead to an underprediction of the number of unprofitable plants that will result from the standard and incorrect conclusions regarding negligible economic impacts resulting from the standard. He asserts that a minimum of 12 percent cost of capital should be used rather than the 10 percent rate assumed in EPA's analysis, and further, that a 12-year equipment life rather than 20 years should be assumed based on the 12-year average small field life reported in a Gas Processors Association (GPA) survey (Docket Entry II-D-59). Moreover, he states that a maximum $3.20/MCF (1980 dollars) price of of natural gas in 1987 is a more accurate prediction than the $4.80/MCF (1980 dollars) value assumed in the Agency's analysis.

The commenter also states that the cost of sour gas treating (i.e., sweetening) is not included in the production costs considered in the economic impact analysis (BID, Table 9-4).

The combined effects of the higher sulfur recovery costs, the added production cost for sweetening, and the lower revenues from sale of sweet gas at $3.20/MCF, justify, in the commenter's mind, a small plant exemption limit of no less than 5 LT/D sulfur feed rate. Further, the commenter suggests an exemption limit of 10 LT/D to ensure that there would be no unprofitable plants in the short run.

Response: The commenter states that a 12 percent cost of capital should be used. The commenter provides no basis for this number. The current economic impact analysis assumes an 11 percent nominal cost of capital based on the current prime rate which converts to a 6 percent real cost of capital assuming a 5 percent inflation rate. The revised economic impact analysis, based on the Gas Processors Association survey, reflects a 12-year well life for plants with sulfur feed rates less than or equal to 20 LT/D and a well life of 20 years for plants with feed rates greater than 20 LT/D.

The commenter suggests a 1987 natural gas price of $3.20/MCF (1980 dollars). The current economic analysis is conducted in 1984 dollars. The natural gas prices for each year of this analysis are as follows:

	(1984 $/MCF)
1985	$3.88
1986	4.06
1987	4.25
1988	4.44
1989	4.64
1990	4.86
1991	5.08
1992	5.32
1993	5.56
1994	5.82

These prices are projected national average wellhead prices for new natural gas. The prices were generated from the hydrocarbon supply model developed by Energy and Environmental Analysis, Inc. and referenced in their July 1984 report entitled "Regional Forecasts of Industrial Residual Fuel Oil and Natural Gas Prices" (Docket Entry IV-A-4). The prices assume natural gas deregulation in 1985. For purposes of comparison, the 1987 price of $3.20/MCF in 1980 dollars suggested by the commenter converts to $4.73/MCF in 1984 dollars. As noted above, the Agency has used a more conservative 1987 price of $4.25. (Conversion factor is 1.477 using the product price index for gas fuels for July 1984 of 1123.5 [Monthly Labor Review, 11/1984. pg. 90, U.S. Department of Labor, Bureau of Labor Statistics (Docket Entry IV-J-4)] and the product price index for gas fuels for 1980 of 760.6 [Statistical Abstract of the U.S., 1981, pg. 462, Table 773, U.S. Department of Commerce, Bureau of the Census (Docket Entry IV-J-2)].)

The commenter correctly notes that the costs of sweetening were erroneously excluded in the previous analysis. The sweetening costs have been included in the current analysis. The results of the current economic analysis (see Appendix A) do not justify a small plant exemption any higher than 1 LT/D.

Comment: The commenter (IV-D-25) stated that if the proposed standards are approved, the "one" sour gas well in a "sweet" gas field would have to be capped and not produced because it would be uneconomical to install sulfur removal equipment. He states that the standard should be withdrawn because the forcing of uneconomical gas plants will result in marginal gas plants not being constructed and usable natural gas not being produced.

Response: The revised economic impact analysis shows that for those plants likely to be built in the future, the promulgation of the NSPS will not make any projected plants that are economical in the baseline uneconomical under the NSPS. Theoretically, some plants with high percentages of H_2S in the sour gas, if built, would be uneconomical under the regulation. It should be noted, however, that the cumulative probability of facilites with these particular gas characteristics being built in the near future is only about 1 percent. (See Appendix A for a presentation of the probability tables.)

Comment: Commenter IV-D-29 cited in evidence of the economic and operating drawbacks of small sulfur plants, the lack of existing petroleum extraction industry sulfur recovery plants in the small plant size range (BID, Table 9-7, Appendix G). Further, he alleged that the sweetening facility sulfur production capacity date in the BID, Table 9-6, shows that economics justify only sweetening plants in the small plant size range.

Response: The revised economic impact analysis shows that there is no economic justification for a small plant cutoff below 1 LT/D. Those plants greater than 1 LT/D likely to be built in the future, that are economical in the baseline, remain economical under the NSPS. The cases that do not maintain profitability under the NSPS have very low (about 1 percent) cumulative probability of being built in the near future due to the combinations of H_2S in the acid gas and in the sour gas. Thus, from a national perspective, the Agency is not imposing significant adverse economic impacts on the industry.

Comment: Two commenters (IV-D-18 and IV-D-29) expressed concern that the increased sulfur recovery resulting from the NSPS would result in a reduction in the price of sulfur. Commenter IV-D-29 stated that if a gas/sulfur plant is a break-even operation, at start-up, a decrease in sulfur price could force the plant to close.

Commenter IV-D-22 also requested that the Agency consider the limited number of locations available for the sale of sulfur in determining revenues from sulfur recovery. The commenter claimed that the limited sales locations could increase transportation costs to the point where they exceed or offset all sale credits.

Response: The additional amount of sulfur that would be available for sale as a result of the NSPS is about 25,000 metric tons in the fifth year after the standards are in effect (1990). The total domestic sulfur supply in 1980 (Figure 9-3 of the BID for the proposed standards) was approximately 12.5 million metric tons. Approximately 2.5 million metric tons of sulfur were imported. Based only on the domestic production figure, the increase in recovered sulfur as a result of the NSPS represents only about 0.2 percent of the 1980 domestic sulfur market. Thus, the impact of the NSPS on the sulfur market is expected to be minimal. It should be noted that Frasch mine production, which represents almost half of the domestic production, has been declining steadily since 1968.

Refer to Section 2.7 for a discussion of transportation costs involved in the sale of recovered sulfur.

Comment: The commenter (IV-D-29) claimed that the Agency relied on a faulty assessment of the economics of sulfur recovery in justifying the 1 LT/D cutoff limit for affected facilities. He states that sulfur recovery at low throughput is not economically attractive or desirable and that the 1 LT/D exemption limit is below a throughput that would sustain the capital and operating cost of a stand-alone sulfur recovery plant. In his opinion, the economics of the sulfur plant should be considered irrespective of revenues from sweet gas sales. He stated that the economic basis for justifying the cutoff in the proposed standards was faulty because it considered revenues from natural gas sales in determining the profitability for sulfur recovery plants.

The commenter stated that the rationale for setting the 20 LT/D cutoff in the NSPS for refinery sulfur plants was based on the economic recovery of sulfur in dollars per long ton. In his view, the approach taken for the natural gas processing 1 LT/D cutoff is analogous to establishing the refinery NSPS cutoff at the level where total oil throughput sustains sulfur recovery costs. He alleged that EPA rejected this approach because of impacts on small refineries. He claimed that the Agency should be consistent and give the same consideration to gas plants since 53 percent of gas plants are owned and operated by businesses other than major oil companies (Reference: Oil and Gas Journal, July 18, 1983, pgs. 90 to 121).

Response: In regard to the commenter's statement that the 1 LT/D cutoff is below a throughput that would sustain the costs of a sulfur recovery plant and that the economics of a sulfur plant should be considered irrespective of revenues from sweet gas sales, the Agency believes that it is appropriate to consider revenues from sweet gas sales in determining the profitability of sour gas processing facilities. The intent of the Agency in promulgating this NSPS is to reduce SO_2 emissions from all new natural gas processing facilities where BDT can be applied without resulting in adverse economic impacts (e.g., plant closings) and without resulting in an unreasonable cost effectiveness (i.e., costs per ton of emission reduction). In determining the profitability of sour gas plants, the Agency appropriately analyzed the effect that the control costs would have on the companies' revenues, which are derived primarily from the sale of sweet gas and in some cases, from the additional sale of recovered sulfur. (It should be noted that revenue from the sale of recovered sulfur was not assumed in the economic impact analysis for plants with sulfur feed rates below 5 LT/D. Projected plants with sulfur feed rates below 5 LT/D were shown to be profitable without the additional sale of recovered sulfur.) Since the purpose of sour gas processing facilities is primarily to produce and sell sweet gas, profitability of sour gas processing facilities is appropriately based on revenues from the sale of product (i.e., sweet gas) as well as the sale of recovered sulfur.

The exemption in the refinery NSPS for sulfur plants with less than 20 LT/D capacity is unlike the exemption in these standards in that it represents an exemption from tail gas treatment requirements (i.e., it is not an exemption from sulfur recovery requirements). Furthermore, in its 4-year review of the refinery NSPS, EPA considered lowering the 20 LT/D cutoff, based on cost-effectiveness. The reason that the cutoff was not lowered was because refinery sulfur recovery plants with feed rates less than 20 LT/D represent a very small fraction of projected growth in capacity (48 FR 57239, December 28, 1983). Cost effectiveness was also a major consideration in determining the cutoff for the standards for natural gas processing plants. The highest incremental cost effectiveness (in dollars per metric ton of SO_2 emissions reduced) of these standards would be about $925/Mg. This is the incremental cost effectiveness for a plant with a sulfur feed rate of 555 LT/D, compared to the baseline. This cost effectiveness is considered to be reasonable by the Agency; consequently, there is no basis for exempting plants with sulfur feed rates ≥2 LT/D.

Comment: The commenter (IV-D-13) believes that the economic analysis supporting the proposed rule and documented in Chapter 9 of the BID should consider the incremental costs compared to the additional sulfur removal. The commenter suggested that costs of increased monitoring, maintenance, recordkeeping, and performance testing should be compared to any increased sulfur recovery rather than gross revenue generated by sales of sour gas. The commenter further stated that although emission controls are considered by industry in evaluating new projects, regulatory action to require additional controls should be evaluated in relation to the base case, which is processing of gas under current regulations. The commenter further stated that projected normal costs in the economic impact analysis (Chapter 9, BID) were incorrect because they did not include the possibility of increased income and severance taxes.

Response: The incremental cost effectiveness of the regulation compared to less stringent control options was the most important consideration in selecting the regulatory alternative on which the standards are based (see preamble to the proposed standards, 49 FR 2660). Incremental cost effectiveness was also the factor used in setting the small plant exemption. The increased costs of the regulation, including increased monitoring and maintenance costs, were evaluated in light of the increased SO_2 emission reduction that would be achieved. The highest incremental cost effectiveness under the regulation would be $925/Mg, a figure judged by the Administrator to be reasonable. [Plants that would spend more than that amount per Mg of additional emission reduction (i.e., plants with sulfur feed rates <2 LT/D) have been exempted from the standards.]

In addition to considering cost effectiveness, the Agency also analyzed the economic impacts of the standards on approximately 1,000 cases. These cases included plants within a wide range of sulfur feed rates and with numerous combinations of percent H_2S in the sour gas and H_2S-to-CO_2 ratios in the acid gas. The results of this analysis indicate that none of the plants that are likely to be built and that would be covered by the NSPS would experience significant adverse economic impacts. The Agency's economic analysis was based on total control costs and their impact on plant profitability, taking into consideration the revenues from the sale of sweet gas. The reason why the Agency believes that it is appropriate to consider such revenues is described in the response to the previous comment.

The economic impact analysis considered neither the possible increase nor possible decrease in income tax but rather assumed a 50 percent tax rate for the entire time period of the analysis. In response to the commenter's concern over the potential for increased severance taxes, an investigation was made into the magnitude of taxes currently levied on typical natural gas producers. The results showed that the nature and magnitude of natural gas production taxes vary widely from location to location and from production facility to production facility (see Docket Entry IV-B-9). However, in most every State where sour natural gas is produced, some type of production rate tax, or severance tax, is assessed on the producer. Tax rates currently levied by the States contacted ranged between about 1 and 10 percent. To account for these taxes, a typical value of 5 percent was factored into the revised economic impact analysis described in Appendix A. Although severance taxes may be increased in some States to provide additional revenue sources, such increases are very difficult to predict. However, any increase would not be expected to affect the overall results of the economic impact analysis.

2.7 COST-EFFECTIVENESS ANALYSIS

Comment A: The commenter (IV-F-1) stated that because an API survey showed an average operating rate of 75 percent of design capacity, different from the value of 100 percent used in the proposed standards, the dollar per ton SO_2 removal costs in the proposed standard should be increased 33 percent.

Comment B: The commenter (IV-D-8) stated that, based on operating experience at his facilities during 1978 through 1983, sulfur recovery facilities have operated at approximately 34 percent of capacity. The commenter stated that these plants once operated at 100 percent capacity, but all plants eventually experience such a decline as a function of field life. His concern is that the cost analysis performed by EPA on the model plants assumed 100 percent operating capacity and that this may affect the conclusions of the analysis. In subsequent discussions with the commenter (Reference Docket Entry IV-D-14), the commenter stated his concern that the entire economic analysis should take into account the fact that despite the decline in volumes, producers try to maximize production and as producing fields age, production declines.

Response: In response to comments, the Agency reviewed the capacity utilization assumption. Commenter B was contacted to determine the age of his gas processing facilities and it was learned that the facilities were at least 23 to 30 years old during the period in which the 34 percent capacity utilization was reported.

An analysis of the available data indicates that average capacity utilization is typically closer to 75 percent. Consequently, the Agency has accepted Commenter A's 75 percent capacity utilization factor and has recalculated the cost effectiveness of the standards. The results of the revised cost-effectiveness analysis affect plant size applicability. The 75 percent capacity utilization assumption was also incorporated into the revised economic impact analysis. The amount of sweet gas and sulfur for sale were each calculated based on 75 percent capacity utilization. The results of the revised economic impact analysis show, even when production declines are taken into consideration, the standards do not impose adverse economic impacts on plants likely to be built in the future.

Assuming a 75 percent capacity factor, the calculated incremental cost effectiveness (ICE) for Alternative III over Alternative II for model plants ≦4 LT/D is as follows:

Model plant size (LT/D)	A ICE based on 100% capacity[a] ($/Mg SO_2)	B ICE based on 75% capacity[b] ($/Mg SO_2)	Increase of B over A
1	1,030	1,393	35%
2	642	840	31%
3	487	652	34%
4	408	568	39%

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[a] Reference BID Table 8-8.

[b] Reference Docket Entry IV-B-6.

The revised analysis incorporated assumptions used in the calculation of ICE for the proposed standards (Docket Entry II-B-44) except:

- 75 percent capacity utilization was used instead of 100 percent,
- a 12-year equipment life (and thus capital amortization period) was used instead of a 20-year life, and
- stack monitoring requirements were eliminated, therefore, monitoring costs were reduced by $39,700/yr (i.e., the stack monitoring costs).

Based on cost-effectiveness considerations, the standards have been revised to exempt facilities with sulfur feed rates less than 2.0 LT/D.

Comment: The commenter (IV-D-7) stated that the Michigan State Air Quality Division investigated available control technologies for sweetening units and concluded that control of SO_2 is economically feasible for most units except for very small plants, i.e., less than 0.1 LT/D sulfur equivalent. The commenter provided copies of the data and noted that different technologies were required for plants handling low- and high-pressure gas. The commenter stated that the decisions on economic feasibility were based on the criterion of cost per 1,000 cubic feet of gas instead of the cost per megagram of SO_2 controlled criterion as considered by EPA. The commenter recommended that EPA use this approach in cost analysis because the cost per ton SO_2 removed may not truly reflect the affordability of the control technology.

Response: The Agency agrees with the commenter that the criterion for economic affordability should be cost per MCF of gas and not cost per Mg of SO_2 controlled. The economic impact analyses, both the original preproposal analysis and the revised analysis, did evaluate affordability on the basis of costs per MCF of gas, not on the basis of costs per Mg of SO_2 as stated by the commenter. The revised analysis indicates that SO_2 controls are affordable by all projected plants without adverse economic impacts. However, even though SO_2 control may be affordable by plants with sulfur feed rates <2 LT/D, these plants would typically spend more than $1,000/ton of SO_2 removed. In the Administrator's judgment, these costs would be unreasonably high for SO_2 control at natural gas processing plants. It is for this reason, rather than affordability, that plants with sulfur feed rates <2 LT/D are exempt from control requirements of the standards.

During the 4-year review of the standards, the Agency will evaluate additional technologies (e.g., caustic scrubbers). If new technologies with reasonable cost-effectiveness are available for smaller plants, the Agency may lower the plant size cutoff.

Comment: The commenter (IV-D-8) is concerned that the cost and technology assumptions made in the model plant/control technology alternative approach to selecting a standard do not represent present or future design conditions at representative natural gas processing plants. The commenter indicated that the five sour gas processing plants operated by his company have standard plant designs, which specify oxidation of all sulfur compounds in acid gas or tail gas streams released to the atmosphere. The commenter was concerned that incineration costs should be considered in the analyses supporting the standard.

Response: The Agency recognizes that incineration costs are a necessary constituent of baseline control costs (i.e., costs incurred in the absence of the NSPS). The appropriate place for consideration of incineration costs is in the economic impact analysis which considers total costs to the plant (i.e., baseline costs and the additional costs necessary to meet the NSPS), and baseline incineration costs were included in the revised economic impact analysis. Since incineration costs are, however, part of baseline costs, they are not considered in the incremental cost-effectiveness analysis.

Comment: The commenter (IV-D-13) claimed that the projected costs, including plant and engineering overhead as well as maintenance costs are greatly underestimated. No cost data were included with the comment.

Response: The cost derivation for 5 to 1,000 LT/D plants and plants with capacities less than 5 LT/D (BID, Chapter 8 and Appendices E and H) were based on data from studies conducted by a sulfur recovery equipment vendor (Docket Entries II-A-16 and II-A-20). Step-by-step sample calculations for converting these data to annualized costs are given in Docket Entries II-B-29 and II-B-44. Efforts were made to include all associated costs components and to make the estimates representative of actual facility costs. As a check, total cost data provided by industry for three actual natural gas processing plants were compared to the estimated costs for similar facility types (Docket Entries II-A-16 and II-A-20). Although exact comparisons could not be made because of differences in the actual plant characteristics and the model plant characteristics, the comparison provided a general indication that the cost estimates were representative of actual costs.

Comment A: Commenters IV-D-27 and IV-D-29 claimed that the Agency overestimated the price of sulfur in calculating sulfur revenues. Commenter IV-D-18 stated that the market available for recovered sulfur and the price at which it can be sold need to be reexamined. Commenter IV-D-27 stated that the sales price per ton is seldom the price received by the gas processing plant and, for example, after transportation cost payments, the net back to a plant in Texas may be \$30 to \$40 per ton less than the sales price and for a plant in Wyoming, the net back may be another \$40 to \$45 lower. Commenter IV-D-29 claimed that the posted price of sulfur has steadily decreased to \$132/LT in July 1983 (C&E News, 1983) and that the posted price and selling price are different. For example, the December 1983 selling price for Eustace, Texas liquid sulfur (f.o.b. Tampa, Florida) was \$80/LT which netted the operator about \$50/LT.

Comment B: The commenter (IV-D-18) agrees with the Agency's assumption in the cost-effectiveness analysis (Chapter 8, BID) that small plants will dispose of rather than sell recovered sulfur and that sulfur disposal costs (and no sulfur credits) will be incurred. However, he believes this assumption should apply to plants up to 20 LT/D of sulfur throughput rather than 5 LT/D as assumed by the Agency.

Response: In response to comments A and B regarding prices received by gas processing plants for recovered sulfur, the Agency contacted several industry representatives and personnel involved in commodity price trends (Docket Entry IV-B-3). According to data obtained from the U.S. Bureau of Mines, the prices paid for recovered sulfur in 1983 ranged from $36/LT to recoverers in the Rocky Mountain areas to $117/LT to recoverers in the Gulf Cost area. The average 1983 f.o.b-plant price paid to recovered sulfur suppliers was $77/LT. From 1979 to 1983 the average f.o.b-plant prices ranged from $49/LT to $100/LT. The results of a survey of natural gas processing plant operators substantiate the Bureau of Mines information. The respondents cited a range of $40/LT to $100/LT received for recovered sulfur. The Agency is aware that posted prices and selling prices are different and that transportation costs vary according to distances from terminals. For sellers of recovered sulfur, transportation costs are generally incurred on a negotiated basis with shipper/transporter agreements dependent on volume, distance, and demand. These rates are regarded as "artificial" and are neither predictable nor standard.

The Agency used $100/LT for recovered sulfur in the cost-effectiveness analyses for the proposed standards. This value was based on information which indicated that elemental sulfur prices increased over 337 percent, from $31.49 per megagram in December 1969 to $137.79 per megagram in March 1981 (BID Table 9-17). Although sulfur prices fluctuated during this period, the trend demonstrated an increase on a consistent basis.

Based on the information received from the above sources, the Agency has revised the assigned price for recovered sulfur from $100/LT to $77/LT. This estimate takes into account transportation costs, fluctuating sulfur prices, and the fact that prices paid for recovered sulfur are generally 10 to 17 percent lower than for mined sulfur. It represents the average 1983 f.o.b-plant price paid to suppliers of recovered sulfur and is consistent with estimates made by gas plant operators.

During the survey of industry representatives regarding sulfur prices, the Agency obtained information regarding recovered sulfur selling/disposal practices with respect to plant size. Of the seven respondents representing plants from 5-20 LT/D, all sold recovered sulfur. Based on this information, the Agency is continuing with the assumption that plants $\geqq 5$ LT/D generally sell recovered sulfur.

Comment: Commenters IV-D-18 and IV-D-29 questioned the Agency's assumptions regarding the amount and H_2S content of sour gas to be developed and the number of new sweetening plants to be constructed. The commenter (IV-D-29) claimed that EPA overestimated both sulfur content and the percent volume of sour gas that would be treated in sulfur recovery plants in the absence of the NSPS. Specifically, he claimed that historical data (Docket Entry II-D-41) show that the portion of sour gas currently treated for sulfur recovery is 31 percent; whereas EPA assumed 75 percent of new sour gas would be treated for sulfur recovery in the absence of the NSPS. Furthermore, the commenter believes that the same historical data indicate that the concentration of H_2S in gas currently treated for sulfur recovery is 5.27 mole percent, rather than the 5.8 number used by EPA.

While the commenter disagreed with the Agency's prediction that 75 percent of new sour gas will be treated for sulfur recovery, he stated that if the Agency was going to assume 75 percent, then it should predict sulfur content based on 75 percent of all the streams in the commenter's survey data. Instead the Agency based its projection of sulfur content on the weighted average H_2S content of only those streams that are currently treated for sulfur recovery. Using the commenter's approach, the Agency's estimate of 5.8 percent H_2S would be reduced to 2.31 percent. Using the 2.31 number, total sulfur recovery capacity would be 1,296 Mg/D instead of 3,244 Mg/D as projected in the BID (Table 9-21).

The commenter claimed that the above differences indicated a need to reevaluate the cost-effectiveness and economic impact analyses.

Response: The EPA's projections of the amount of sour gas that would be treated for sulfur recovery and of the sulfur content of that gas were based on: 1) an analysis of data demonstrating the trend toward higher H_2S concentrations (Table 9-22 of the BID), 2) an analysis of the July 1982 survey data provided by the commenter, and 3) discussions with sulfur recovery equipment vendors and regulatory officials with experience in the sour gas processing industry. These discussions (Docket Entries II-D-23, 24, and 25) indicated that, under baseline conditions, sulfur will be recovered from about 75 percent, by volume, of the newly discovered sour gas that will require sweetening prior to sale to pipeline companies. The other 25 percent will be sweetened but will not be treated for sulfur recovery. This 75 percent estimate takes into account the historical trend toward deeper wells with higher H_2S contents. Data in the BID illustrate this trend (see Table 9-22, pg. 9-44). The estimated average H_2S concentration has increased from about 1-2 percent in the 1960's to 5-6 percent in the late 1980's. In the baseline, decisions about whether or not to install sulfur recovery equipment are driven largely by State regulations and economic incentives. The expectation is that these incentives in conjunction with the trend toward deeper, more sour wells will result in roughly 75 percent by volume of new sour gas being subjected to sulfur recovery.

The 5.8 percent H_2S number that the Agency used to predict the H_2S content of future sour gas that will be treated for sulfur recovery in the baseline (i.e., in the absence of the NSPS) was derived from the gas plant survey data provided by the commenter in July 1982 (BID, Appendix G). The Agency calculated a weighted average percent H_2S content for all the streams in the survey that were identified as being treated for sulfur recovery. According to this survey, decisions to employ sulfur recovery equipment have, in the past, corresponded to an average H_2S concentration of 5.8 percent. The 5.8 percent value also was compared to the H_2S concentration data prepared in evaluating the trend toward deeper more sour wells (BID, Table 9-22). These data support the 5.8 percent H_2S estimate and it is expected that, in the absence of the NSPS, decisions to employ sulfur recovery will continue to be based on this same concentration.

The 5.27 percent H_2S value suggested by the commenter is based on a revised survey data set (Docket Entry II-D-41, October 29, 1982) that was received by the Agency after the proposal BID had been prepared. The Agency agrees that the revised data indicate that the 5.8 percent number should be updated to 5.27 percent. While the difference between the two numbers (about 10 percent) did not, in the Agency's opinion, warrant revision to the proposal BID, the Agency did use the 5.27 percent number in the analyses supporting the final standard.

The commenter's suggestion that the projected sulfur content of new gas treated for sulfur recovery should be based on 75 percent of all the gas streams in the API survey (if the Agency continues to use 75 percent) would result in a significant understatement of the sulfur content. The commenter's 2.31 percent H_2S number implies that the H_2S content of future sour gas treated for sulfur recovery will mirror the H_2S content of all sour gas in the survey data which includes, primarily, gas streams that are not currently treated for sulfur recovery. The 5.8 percent number (now revised to 5.27) corresponds to the sulfur content of sour gas that is currently treated for sulfur recovery because the purpose of the number is to predict the sulfur content of sour gas that will be treated for sulfur recovery in the future (in the baseline).

In summary, the Agency reviewed data that served as the basis for the projections of the amount of sour gas that would be treated for sulfur recovery and of the sulfur content of that gas. As stated earlier, the Agency revised its projection of percent H_2S concentration from 5.8 percent to 5.27 percent; however, the Agency believes that the other assumptions and projections remain valid.

Comment: The commenter (IV-D-29) questioned the basis for the statements in the preamble to the proposed regulation that the NSPS represents a 78 percent reduction of SO_2 emissions from SIP levels and that "a large potential for reduction in SO_2 emissions exists with the projected growth" in the industry. He claimed that the economics and existing State regulations have caused the petroleum extraction industry to install more sulfur recovery capacity than that assumed by the Agency. He claimed that API data show 94 percent of the sulfur in all onshore sour natural gas was subject to sulfur recovery during 1981. Further, he claimed that current PSD requirements for BACT are a marked reduction from the SIP levels. Consequently, he feels EPA's baseline, Regulatory

Alternative I is low, and he stated that this calls into question the emission reduction benefits and cost analyses of Regulatory Alternatives II through VI.

Response: In developing NSPS, baseline control levels are estimated for the purpose of evaluating emission reduction and cost impacts. As such, baseline control levels are intended to represent controls typically required across the nation in the absence of NSPS. While it is true that some States have required, for specific plants subject to PSD requirements, higher levels of SO_2 control than the typical SIP level, these requirements have been site-specific and thus are not considered to be good indicators of typical nationwide control levels.

The commenter claimed that API data show that 94 percent of the sulfur in all onshore sour gas was treated for sulfur recovery during 1981. For comparison with this figure, the Agency estimated the percent of sulfur assumed to be treated for sulfur recovery in the baseline. The Agency projects a 5-year total sulfur recovery capacity of 3,244 Mg/D (Table G-4 of the BID) and a total sweetening capacity without sulfur recovery of 38.9 Mg/D (Table G-7 of the BID). Based on these numbers, the Agency has projected that about 99 percent of the sulfur would be treated for sulfur recovery in the baseline. Compared to the commenter's 94 percent figure, it would appear that the Agency did not underestimate the level of control typically required in the baseline.

Comment: The commenter (IV-D-29) claimed that the Agency calculated costs of \$171 to \$408,000/Mg SO_2 removed (BID, pgs. 8-17 and 8-19) but did not directly use those costs in setting the plant size cutoff limit. The commenter stated that actual incremental costs of sulfur recovery are in the \$1,030 to \$9,840/LT range.

Response: The commenter references several cost per megagram of SO_2 removed (cost effectiveness) figures from the BID and alleges that the Agency did not directly use those costs in setting the plant size "cutoff limit." As stated in the preamble to the proposed regulation, the Agency did consider, among other factors, the incremental cost effectiveness, or the ratio of the additional cost and the additional emission reduction for one regulatory alternative compared to the next more stringent alternative in selecting Regulatory Alternative III as the basis of the standard. Because Regulatory Alternative III affects only sweetening units of ≥2 LT/D sulfur feed rate, it does implicitly establish a "cutoff limit" as referred to by the commenter. Furthermore, the model plant/control technology combinations making up the regulatory alternatives maintain consistent incremental cost effectiveness and to this extent, cost effectiveness values, including several values referenced by the commenter, were used in setting a "cutoff limit."

The manner in which the commenter referred to the numbers from the BID, however, indicate a misunderstanding of how those numbers relate to the decisions made by the Agency. The $171/Mg value is the cost effectiveness of the 2-stage Recycle Selectox process (Regulatory Alternative III) compared to incineration (the baseline control) for a 5 LT/D plant. The $408,000/Mg value would be the incremental cost effectiveness of a 3-stage Recycle Selectox process compared to a 2-stage process for a <0.1 LT/D plant. Even the most stringent alternative considered by the Agency did not include controls for any plants 0.1 LT/D or smaller in size. Consequently, the $408,000/Mg incremental cost effectiveness value was not pertinent to the selection of the basis for the standard. Neither was any other model/plant control technology combination resulting in an incremental cost effectiveness of greater than $44,800/Mg pertinent to the final selection by the Agency. The incremental cost effectiveness values that were considered in evaluating the regulatory alternatives are listed in Table 8-8 of the BID (pg. 8-16). Review of this table also shows that the commenter's allegation that actual incremental costs of sulfur recovery are in the $1,030 to $9,840 range is in error. The highest incremental cost effectiveness resulting from Regulatory Alternative III, the selected basis for the standard, is $1,030/Mg for a 1 LT/D plant size.

In response to comments on the proposed standards, the Agency conducted a revised cost-effectiveness analysis incorporating updated assumptions (see Section 2.7). The revised analysis shows that the highest incremental cost effectiveness resulting from Regulatory Alternative III is about $1,400/Mg for a 1 LT/D plant (Docket Entry IV-B-6). However, the standards have been revised to exempt plants <2 LT/D from the control requirements of the standards. The incremental cost effectiveness for a plant with a sulfur feed rate of 2 LT/D is $840/Mg.

2.8 SMALL PLANT EXEMPTION

Sulfur Intake Rate Cutoff

Several commenters recommended changing the 1 LT/D cutoff provision specified in the proposed standards. Two commenters (IV-D-10 and IV-D-28) suggested a 5 LT/D cutoff; six (IV-D-12, IV-D-16, IV-D-22, IV-D-27, IV-D-30, and IV-D-31) suggested 10 LT/D; and seven (IV-F-1, IV-F-5, IV-D-11, IV-D-13, IV-D-20, IV-D-23, and IV-D-29) proposed a 20 LT/D cutoff. Commenter IV-D-18 recommended that plants less than 100 LT/D be regulated less stringently. Various reasons for revising the cutoff specification were cited and these are discussed below.

Comments: Commenter IV-F-3 stated that adopting a higher cutoff would allow some plants with marginal economic success to continue gas production and allow production of fields which might not otherwise be produced (i.e., because of the standards as proposed). This commenter and others (IV-D-12, IV-D-20, IV-D-23, and IV-D-29) stated that the proposed standards could cause many small wells containing H_2S to go unproduced. Commenter IV-D-20 stated that the possibility of premature abandonment of gas and sulfur recovery plants is greater for plants less than 20 LT/D and that the effects of the discouragement of natural gas production could contribute to supply disruptions. Commenter IV-D-31 stated that a sulfur plant may be required for as little as one or two wells and the wells may be short-lived. Commenters IV-F-3, IV-D-18, and IV-D-27 also reported that variability in well production affects the economic viability of small plants. In addition, commenter IV-F-3 restated the need for the preamble to include more small plant economic data, referred to the data on this subject submitted previously (by the commenter) and urged other members of industry to submit additional information. The commenter stated that he had provided supporting documentation for recommending an exemption for plants with sulfur feed rates less than 5 LT/D. Commenter IV-D-20 stated that because of the high investment costs of sulfur recovery plants relative to the value of sulfur and the lower costs of SO_2 emission reduction from other industries, the 1 LT/D cutoff limit is unreasonable and inequitable.

Response: The preamble to the proposed rule discussed the concerns raised by some industry representatives that sweetening plants producing acid gas with 5 LT/D or less of sulfur could experience unreasonable economic impacts. These concerns mirror those of the commenters, which identified variability in well or field production rates and other factors influencing the economics of small plants. The Agency understands the commenters' concerns regarding "variability in well production" to mean that the economic life of a particular facility may be less than the 12-year average life assumed in the standards. The 12-year life assumption is based on an industry survey of small plants (Docket Entry II-D-59) that indicated the average life of plants ≦20 LT/D is 12 years. Subsequent economic analyses, using a facility life of 12 years, showed no adverse impacts.

The data submitted previously by the commenter (IV-F-3) (Docket Entry II-E-40) concerning economics of small plants provided some insight into the methods of economic analysis used by natural gas producers, but was not specific enough to indicate the exact economic criteria used in the decision-making process for proceeding with well development. For example, the commenter provided data concerning the cumulative percent of total wells vs. reserves. Although these data serve as an indicator of potential number of wells (and reserves) affected, a more helpful submittal would include a similar distribution of only sour wells, which could be affected by the standard. Also, although some cost data are provided, the process used to determine rate of return on investment and the "acceptable" rate of return would be more useful.

As part of the standards development process, six regulatory alternatives were identified to control SO_2 emissions from onshore natural gas processing plants. Based on a review of incremental cost effectiveness for each of these alternatives, the Administrator selected Regulatory Alternative III as a basis for the standard. In the economic impact analysis (Chapter 9, BID for the proposed standards), no plant curtailments were predicted under Regulatory Alternative III and costs were not expected to cause any increase in the number of plants unable to cover total production costs (Table 9-27, BID for the proposed standards). Subsequent to proposal of the standards, a revised economic impact analysis was conducted using a different methodology and incorporating several updated assumptions including gas prices, equipment life, recovered sulfur prices, and baseline sweetening costs (see description in Appendix A). The results of the analysis were not significantly different from the results of the preproposal analysis. The standards are not expected to have an effect on incentives to develop new sour gas fields. Sizes of model plants, ranging from 1.0 to 1,000 LT/D were included in the economic impact analysis. The analyses conducted in developing the standard do not support citations from the commenters that the standard will place an unnecessary burden on small producers. Thus, there is no economic basis for exempting facilities with sulfur feed rates ≥1 LT/D. The 2 LT/D cutoff determination was made on the basis of cost effectiveness.

Under all regulatory alternatives, nationwide costs of compliance are approximately 2 percent of the total projected value of sweet gas sales from sour natural gas processing. Thus, under Alternatives I through VI, the impacts of SO_2 emission control costs on expected returns from exploration and development are small and the effect of these alternatives on exploration and development of new wells is likely to be negligible.

The effects of variations in throughput are discussed later in this section.

Comments: Four of the commenters (IV-F-1, IV-F-5, IV-D-20, and IV-D-29) who suggested a 20 LT/D cutoff cited, as a precedent, the 20 LT/D exemption for sulfur recovery plants in the refinery NSPS.

Commenter IV-D-16 recommended a 10 LT/D cutoff and said that an exemption for remote gas plants should be at least as large as the exemption for urban refineries.

Response: The exemption in the refinery NSPS for sulfur plants with less than 20 LT/D capacity is unlike the exemption in these standards in that it represents an exemption from tail gas treatment requirements (i.e., it is not an exemption from sulfur recovery requirements). Furthermore, in its 4-year review of the refinery NSPS, EPA considered lowering the 20 LT/D cutoff, based on cost-effectiveness. The reason that the cutoff was not lowered was because refinery sulfur recovery plants with feed rates less than 20 LT/D represent a very small fraction of projected growth in capacity (48 FR 57239, December 28, 1983). Cost effectiveness was also a major consideration in determining the cutoff for the standards for natural gas processing plants. The highest incremental cost effectiveness (in dollars per metric ton of SO_2 emissions reduced) of these standards would be about $925/Mg. This is the incremental cost effectiveness (Alternative III vs. Alternative II) for a plant with a sulfur feed rate of 555 LT/D. This cost effectiveness is considered to be reasonable by the Agency; consequently, there is no basis for exempting plants with sulfur feed rates ≥2 LT/D.

Comment: Commenters IV-F-5 and IV-D-13 stated that changing the exemption to 20 LT/D would not significantly increase SO_2 emissions because the recommended change would exempt less than 7 percent of total available sulfur plant feed, or 0.25 percent of industrial SO_2 emissions.

Response: The fact that changing the cutoff limit to 20 LT/D would exempt less than 7 percent of the total available sulfur plant feed and that these small plants may contribute only 0.25 percent of total national industrial SO_2 emissions, as stated by the commenter, does not alter the Administrator's conclusions. The purpose of the cutoff is to cause the standard to reflect BDT. The amount of emissions at issue is irrelevant to that purpose. In any event, emissions from plants with sulfur feed rates ≤20 LT/D are considered significant by the Agency and can be significantly reduced at reasonable costs. Emissions of SO_2 from plants less than 20 LT/D, based on the information provided by the commenter, represents over 60 percent of the emissions from the source category. The emissions data cited by the commenters reinforce rather than obviate the need for regulating small facilities.

Comment: Commenters IV-D-10, IV-D-18, and IV-D-20 based their recommendations for a higher cutoff specification on the premise that smaller plants emit substantially less SO_2 than larger plants, and because controls are least cost effective at smaller plants where compliance costs are higher. Commenter IV-D-10 suggested a cutoff of 5 LT/D; IV-D-18 suggested 20 LT/D; and IV-D-18 did not specify a cutoff but recommended that plants less than 100 LT/D be regulated less stringently. Commenter IV-D-22, recommending a 10 LT/D cutoff, said that the cost of sulfur removal equipment is approximately the same irrespective of capacity.

Response: Small plants are regulated by the standards because they emit SO_2 that can be controlled to a level reflecting BDT. A 5 LT/D plant under typical SIP regulations can emit about 3,500 Mg (3,900 tons) of SO_2 per year. As indicated in Chapter 9 of the Volume I BID (Table 9-9), in 1979, 19 facilities with capacities less than 10 LT/D were in operation. Over 67,500 Mg of SO_2 could be emitted from those facilities, assuming each plant emits 3,500 Mg SO_2/year. On the other hand, a large plant (>1,000 LT/D) may emit as much as 23,900 Mg SO_2 (26,400 tons SO_2) per year under baseline control levels. In 1979, only one plant this size was operational. Thus, based on the distribution in 1979, several small plants emit more SO_2 than one large plant. Given the distribution of new facilities expected to be constructed in the future, this trend will continue. The Agency considers emissions from small plants to be significant.

The cost effectiveness for a complete range of plant sizes was evaluated during development of the proposed standards. The maximum cost in dollars per ton SO_2 removed, $1,030 [since proposal, this number has been recalculated (see Section 2.7)], for a 1 LT/D plant under Alternative III was deemed by the Administrator to be reasonable. In addition, the economic impact analysis showed no adverse effects on small plants from Regulatory Alternative III, the alternative upon which the standards are based. The revised analysis shows that the incremental cost effectiveness resulting from Regulatory Alternative III is about $1,400/Mg for a 1 LT/D plant and $840/Mg for a 2 LT/D plant (Docket Entry IV-B-6). The cost effectiveness for 1 LT/D plants has been judged to be unreasonable; therefore, the standards have been revised to exempt plants <2 LT/D from the control requirements of the standards.

Comment: Three commenters (IV-D-12, IV-D-28, and IV-D-29) questioned the availability of sulfur control technology for plants with small (<5 LT/D and <20 LT/D) production rates. Commenter IV-D-28 added that some information on 2-stage Recycle Selectox is claimed as proprietary by the vendor and is, therefore, unavailable for evaluation.

Response: The Recycle Selectox technology (the technology evaluated by the Agency for application to small plants) has been successfully demonstrated on a commercial scale at natural gas processing facilities in West Texas and at another facility with an acid gas stream (Claus process tail gas) with 2 percent H_2S. Other natural gas processing facilities employing the Recycle Selectox technology are in the planning stages. In addition, other technologies have been advanced in recent years (e.g., Slurrysweet$_{TM}$ and LoCat$_{TM}$, etc.) for the purpose of recovering or removing sulfur from low flow, H_2S lean acid gas streams. On this basis, the Agency concludes that BDT exists for small affected facilities.

With respect to any proprietary data on the Recycle Selectox process, the Agency assumes that vendors of this process will make available all the information necessary to satisfy a potential customer's questions. It should be pointed out, however, that these standards do not require the use of any particular process or technology. The Agency has the responsibility of basing the standards on the capability of what is determined to be the BDT. For small processing plants, that technology is the Recycle Selectox process. Any other process capable of meeting the required sulfur recovery efficiencies can be used.

Comment: Four commenters (IV-D-23, IV-D-27, IV-D-29, and IV-D-31) discussed operating problems encountered by small sulfur plants. These problems may lead to the disruption of gas plant operation. The problems identified by the commenters included heat loss, which makes process control difficult, and variations in sulfur concentration at the gas plant inlet, which can sometimes make a sulfur plant inoperable. This latter problem was said to be most significant at small plants fed by a few wells. Commenter IV-D-27 stated that in the absence of a 10 LT/D exemption, there should be an allowance for greater fluctuations in sulfur recovery efficiency for plants below 10 LT/D capacity. He stated that small plants may be connected to as few as 10 to 12 wells in contrast to a typical plant of greater than 20 LT/D, which usually has an adequate number of gas sources to survive the loss of one well.

Response: In response to these comments, the Agency discussed the effect of decreased throughput on recovery efficiency with Ralph M. Parsons Company, an engineer design firm with expertise in sulfur recovery facilities (Docket Entry IV-E-1). Based on these discussions, the Agency concluded that the recovery efficiencies required by the standard are achievable and representative of BDT. Variations in throughput are accommodated by the design of the processing equipment. The sulfur recovery technologies can operate over a wide capacity range. The turndown capabilities of plants are discussed in response to comments in Section 2.4. Process instrumentation also allows for corrections to accommodate smaller variations occurring over shorter time intervals. The plants evaluated by the Agency employ gas analyzers to measure the ratio of H_2S to SO_2 in the process tail gas as a trim control to ensure that only the correct stoichiometric amount of process air is used to maintain the desired 2 to 1 H_2S to SO_2 ratio. Maintenance of the 2 to 1 H_2S to SO_2 ratio ensures design efficiencies regardless of throughput. Also, heat loss was not identified as an irresolvable operating difficulty. Insulation steam tracing and other practices can be used to mitigate potential heat balance problems. The Agency acknowledges, however, the commenter's concern that small plants experience proportionately greater variations in inlet conditions and corresponding operating difficulties. It was because of this concern that plants with feed rates between 2 and 5 LT/D are required to meet a uniform 79 percent recovery efficiency during the initial performance test and 74 percent efficiency thereafter. These efficiencies were established below the optimal performance capabilities to account for flow fluctuations and other uncertainties related to day-to-day performance at facilities in this size range. Start-of-run sulfur recovery efficiencies for the technologies considered as BDT (i.e., Recycle Selectox, 2-stage) range from 80.6 to 92.3 percent.

Comment: Two commenters (IV-D-23 and IV-D-31) stated that small plants are typically located in remote areas far from skilled labor pools and are unattended 12 to 16 hours per day. The commenters propose that these plants should be exempt from the control requirements.

Response: The Agency has evaluated the potential impacts of the proposed standards on small plants and has revised the standards to address the issue of small plants being unattended for 12-16 hours per day and not having technicians sufficiently skilled to operate continuous emission monitors.

(1) Based on the results of an incremental cost-effectiveness analysis of the proposed monitoring requirements and an alternative monitoring approach (see Docket Entry IV-B-31), plants with sulfur feed rates <150 LT/D have been exempted from continuous emission monitoring

requirements (see Section 2.7). These plants may, instead, calculate emission reduction efficiency daily by comparing the amount of sulfur recovered to the amount of sulfur entering the sulfur recovery unit.

(2) The standards have also been revised to require sulfur production and emission monitoring on a 24-hour instead of a 12-hour basis to accommodate plants unattended for portions of the day (see Section 2.12).

The economic impact of the standards on plants ≧1 LT/D has been analyzed and determined to be reasonable. In addition, the cost effectiveness of the standards on plants with sulfur feed rates ≧2 LT/D has been judged by the Administrator to be reasonable. Thus, there is no basis for exempting plants.

Comment: Commenter IV-D-29 stated that the proposed cutoff would prevent process improvement in existing small gas plants. An example was presented in which a fuel inefficient gas liquids plants would be replaced with a new, more fuel efficient cryogenic plant. Completing the project requires removal of acid gases from inlet sour natural gas. If the 1 LT/D cutoff were exceeded, a sulfur plant would be required to treat the acid gas. The commenter claimed that the cost of the sulfur plant could make the entire project uneconomical. The commenter recommended that the affected facility size be increased and stated that the change would encourage small, outmoded plants to make improvements in fuel efficiency by lessening the possibility of triggering the NSPS.

Response: The economic impact analysis (Chapter 9, Volume I BID) and the revised economic impact analysis (see Appendix A) indicate that under Regulatory Alternative III, upon which the standards are based, no adverse impacts are expected for plants with sulfur feed rates greater than or equal to 1 LT/D. The costs of sulfur removal were an integral part of the analyses. The Agency has determined that projected new plants with sulfur feed rates greater than or equal to 1 LT/D complying with the proposed standards will not be unprofitable.

As discussed in the previous response, the cutoff for plant size control requirement applicability has been changed to 2 LT/D, based on cost-effectiveness considerations.

2.9 CATALYST LIFE

Several commenters questioned the assumptions of catalyst life expectancy for Claus and Recycle Selectox processes.

Comment: Two commenters (IV-F-1 and IV-D-22) believed that catalyst life for units at small plants may be shorter than the 4-year period used in the basis for the proposed standards because small plants are not staffed continuously and greater potential exists for operating upsets resulting in catalyst degradation.

Response: Information provided by industry (Docket Entries II-B-26, II-B-27, and IV-E-3) indicates that the useful life span of a Claus catalyst bed ranges from approximately 1 to 7 years, with a 3-year to 5-year range occurring most frequently. The information does not show any correlation between catalyst life and plant size.

The Agency understands that catalyst life can be quite short, in some cases and in other cases, much longer than average. However, based on the information obtained during development of the standards, the Agency continues to regard 4 years as representative of a typical useful catalyst life.

Comment: The commenter (IV-F-2) stated that, based on operating experience, the reductions in sulfur recovery efficiency listed in the proposed standards of 1.68 percent and 1.88 percent per year for 2-stage and 3-stage Recycle Selectox units due to catalyst degradation are much too high. The commenter said that the Sid Richardson Recycle Selectox unit has shown no significant decrease in sulfur recovery efficiency because of catalyst degradation after 2 years of operation. The commenter also stated that recovery loss (rate of reduction in sulfur recovery efficiency) for 3-stage Claus units in the Volume I BID (Chapter 4) may be low.

Response: The Recycle Selectox catalyst degradation rates questioned by the commenter of 1.68 percent per year (2-stage process) and 1.88 percent per year (3-stage process) are based on process design performance data prepared by the Ralph M. Parsons Company. The rate of reduction in sulfur recovery efficiency for the Recycle Selectox process was calculated from start-of-run and end-of-run efficiencies. The 4-year period is the average of the 3- to 5-year range of actual catalyst lives experienced by sour gas processing plants surveyed during the development of the standards (Reference Docket Entry II-B-28). The sulfur recovery performance data developed by Parsons assumed a 5-year life of the Selectox catalyst and a 3-year life of the alumina Claus stage catalyst for the Recycle Selectox processes (≤5 LT/D sulfur feed) considered.

With specific regard to the Recycle Selectox process, the Agency realizes that the limiting factor on catalyst life is the alumina Claus catalyst and not the Selectox catalyst. The EPA also realizes that Claus catalyst life is influenced by the operation of the particular process. The survey mentioned above indicated Claus catalyst lives as short as 1 year (due to process malfunctions) and as long as 6 years or more with steady process operation. The limited data available on Selectox catalyst degradation (Reference Docket Entry II-D-57) indicate little loss of performance with time reportedly due to its insensitivity to fouling from carryover of organic compunds in the acid gas. The Claus catalyst, however, is believed to degrade at about the same rate in the Recycle Selectox process as it does in other Claus-based sulfur recovery plants. The 1.68 and 1.88 percent per year degradation rates are acknowledged as being the "high end" of what would be expected under normal operation conditions and are attributed to degradation of the Claus catalyst and not the Selectox catalyst.

The Selectox process referred to by the commenter is installed to treat the tail gas from a sulfur recovery unit. As such, it would not experience the hydrocarbon fouling and resulting catalyst degradation of a Recycle Selectox plant installed on an acid gas stream from a sweetening unit. Consequently, his conclusion about no decrease in sulfur recovery efficiency may be correct only for tail gas units.

2.10 1000°F TEMPERATURE REQUIREMENT

The Agency received fifteen comments (IV-F-1, IV-F-2, IV-F-3, IV-F-5, IV-D-2, IV-D-8, IV-D-16, IV-D-18, IV-D-22, IV-D-23, IV-D-24, IV-D-27, IV-D-29, IV-D-30, and IV-D-31) regarding the requirement (in the proposed standards) that incinerators be operated at 1000°F. All were in opposition to the specification of a certain temperature. The bases of this opposition and alternatives offered by the commenters are presented below.

Comment: Eight commenters (IV-F-1, IV-F-2, IV-F-5, IV-D-8, IV-D-23, IV-D-24, IV-D-29, and IV-D-30) pointed out that the requirement precludes the use of catalytic incinerators which are capable of effectively converting H_2S to SO_2 at temperatures below 1000°F.

Comment: Two commenters (IV-D-2 and IV-D-16) suggested that temperature alone does not ensure the oxidation of residual sulfur-containing compounds. Incinerator temperature in incinerators is only one of several factors which affects complete combustion. These factors include residence time of gas in the combustion zone of the incinerator and the mixing of sulfides with make-up air.

Comment: Eight commenters (IV-F-3, IV-F-5, IV-D-16, IV-D-22, IV-D-23, IV-D-24, IV-D-27, and IV-D-29) stated that the 1000°F requirement is wasteful in that it results in unnecessary increased fuel consumption.

Comment: Six commenters (IV-F-3, IV-D-8, IV-D-18, IV-D-27, IV-D-29, and IV-D-31) recommended that temperature requirements for incinerators be the minimum temperature necessary to oxidize all sulfur compounds to SO_2. It was suggested that this temperature be determined during the performance test and that a 95 to 99 percent conversion efficiency would establish a site-specific temperature requirement.

Comment: One commenter (IV-D-24) suggested the requirement of an 850°F minimum thermal oxidation temperature and a 650°F minimum catalytic oxidation temperature for sulfur recovery incinerators.

Comment: One commenter (IV-D-16) stated that if the only purpose of the temperature requirement is to ensure conversion of H_2S to SO_2 so that the continuous SO_2 monitor can detect sulfur leaving the stack, then a provision should be added to remove the 1000°F temperature requirement if a total sulfur monitor is installed that can accurately measure total sulfur emissions (COS, CS_2, H_2S, and SO_2).

Alternatively, the commenter stated that if the purpose of the temperature requirements is related to concern of health effects of unburned H_2S, the Agency should state that fact and set a maximum allowable H_2S stack concentration, based on the Agency's risk assessment of the impacts of H_2S on public health. In such a situation, the plant owner could decide how to best meet the health standard based on conditions at his facility. At some plants, the commenter claimed that "less than complete" combustion may be acceptable if the H_2S concentration is within the health standard limit.

Comment: One commenter (IV-D-30) recommended deletion of the 1000°F temperature requirement because the requirement was a design limit and conflicted with the provisions of Section 111(b)(5) of the Act, which prevents the Administrator from adopting a particular emission control technology. The commenter stated that the Agency may impose a design or work practice standard only if it is not feasible to prescribe or enforce a standard of performance. Because, in the commenter's opinion, the proposed standard contains a standard of performance in the form of a minimum sulfur recovery efficiency, Section 111(b)(5) of the Act appears to preclude the adoption of design criteria.

Response: The purpose of the temperature requirement was to ensure complete oxidation of total reduced sulfur (TRS) in the tail gas to SO_2. Since the required monitoring devices measure only SO_2, total conversion to detectable species is necessary for accurate emission and sulfur recovery efficiency determinations. In the absence of total conversion, monitors for H_2S, TRS, and SO_2 would be necessary.

The Agency understands that incinerator efficiency is a function of design (residence time, flow patterns, etc.) and operation (temperature). While the design parameters are specific and predetermined for each incinerator, the operatonal parameters can be more easily adjusted.

The Agency has reviewed the requirement that incinerators be operated at 1000°F. Based on comments from both industry representatives and State regulatory agencies, the Agency is deleting the 1000°F temperature requirement for incinerators. Instead, a site-specific temperature, to be determined during the performance test, will be required for those facilities required to have stack monitors and electing to monitor only

SO_2 in the stack gas. This temperature must ensure conversion of ≧98 percent of the sulfur compounds to SO_2, in order to ensure an accurate sulfur recovery efficiency calculation. The use of site-specific minimum temperature determinations will allow plant operators to provide for oxidation of residual sulfur compounds to SO_2 in a manner best suited to that particular operation. Thus, catalytic incinerators will not be precluded from use in complying with the proposed standard. Also, if a given plant demonstrates that operating at a temperature less than the previously required temperature of 1000°F, will yield ≧98 percent conversion of sulfur compounds to SO_2, then that lower temperature will be the minimum required for that plant. If, on the other hand, a given plant cannot attain ≧98 percent SO_2 conversion ratio at 1000°F, then that plant will be required to operate at a higher temperature or to monitor both SO_2 and other unoxidized sulfur compounds (TRS monitoring).

Deleting the 1000°F temperature requirement and replacing it with a minimum temperature to ensure ≧98 percent SO_2 conversion does not indicate a more lenient approach. Instead, plant operators can more economically comply with the proposed standard, and operate incinerators at lower temperatures, as long as the oxidation process ensures ≧98 percent of the total sulfur content of the stack gases (expressed as SO_2) in the form of SO_2.

Response to the commenter (IV-D-30) who stated that the temperature requirement conflicted with Section 111 of the Act is as follows:

The proposed standards in question are performance standards in which the equations for determination of emission limits are consistent with the intent of the Act for performance standard requirements. The 1000°F temperature requirement for incinerators was a requirement relating to the operation or maintenance of a source to assure continuous emission reduction. The Agency is authorized by Section 302(1) of the Act to impose such requirements as part of the performance standard.

2.11 FORMAT OF THE STANDARD

Comment: Two commenters (IV-F-1 and IV-D-8) requested that the initial compliance sulfur recovery efficiency requirements be used as a guideline, not a standard. In their opinion, the initial efficiency requirements may necessitate installation of an expensive unit to attain initial compliance and the unit would not be needed thereafter to meet the efficiencies required by the second equation. The example was offered of a Sulfreen or CBA process that may be needed to meet the initial compliance requirements for a 100 LT/D facility with 80 percent H_2S in the acid gas plant. A 3-stage Claus process plant likely could meet the long-term requirements.

Another commenter (IV-D-16) stated that the proposed standard consisted of two standards, a "start-up standard" and a "less restrictive operational standard." The commenter claimed that the first standard is excessive and unwarranted and that plants may have to install additional control equipment to meet the "first standard," while less costly equipment could meet the "second standard" requirements. The commenter recommended that the NSPS should be modified to use the "first standard" as a guideline and not a requirement.

Response: In referring to the "two compliance tests" and "two standards" the commenters are referring to the first equation which determines the minimum emission reduction that must be achieved during the initial performance test and the second equation which determines the minimum efficiency that must be achieved on a continuous basis. Only one "compliance test" is required, providing the facility adequately demonstrates compliance with the initial sulfur recovery efficiency requirement during the performance test and demonstrates through the monitoring requirements that the continuous sulfur recovery efficiency requirement also is being achieved. A second, or multiple compliance test(s) may be required by the permitting authority to prove compliance with the continuous sulfur efficiency requirement. This normally would occur only if the continuous monitoring measurements indicated excess emissions at the facility.

The first equation is based on the recovery efficiencies achievable using BDT with a 1-year old catalyst. The first equation reflects the initial performance of the BDT upon which the standard is based and is designed to cause installation of technology which will initially achieve this level of performance. The performance established by this equation is expected to influence the sulfur recovery process which an owner or operator selects to comply with the standards. It is the equation that is used by enforcement personnel to determine initial compliance.

The second equation ensures proper operation and maintenance of the sulfur recovery unit on a continuous basis. The second equation by necessity requires a lower efficiency than the first since it is based on catalyst degradation rates over a 4-year period. The purpose of the second equation is to provide an indication to enforcement officials of daily operation and maintenance. Based on daily calculations of the actual recovery efficiency of a plant in relation to its required efficiency, enforcement officials will determine whether a compliance problem exists that warrants a compliance test. The results of a compliance test, conducted after an initial demonstration of compliance, would be compared to the second equation to determine compliance.

The cost analyses prepared in support of the standards are the costs of the technologies representative of BDT that will be used to achieve the higher initial sulfur recovery efficiency requirement. Consequently, the cost of the technologies that will be used to meet the first equation have been evaluated and determined to be reasonable. For these reasons, the initial sulfur recovery efficiency is necessary as a requirement and is not merely a guide.

Comment: Another commenter (IV-F-4) stated that the "sliding standard" would be difficult to enforce and unfair to certain plants. He claimed that the requirements of an affected facility would change from day to day and reviewing plant records would require significant portions of enforcement agency personnel time.

Comment: Commenter (IV-D-22) recommended a single SO_2 emissions rate format for the standard instead of the proposed emission reduction efficiency format. The commenter stated his concern is that the proposed efficiency format presents a "moving target" because the H_2S/CO_2 ratio does not remain constant for the life of the plant and could place owners/operators in violation of the standard before the requirements of the standard could be determined.

Response: The Agency assumes that by "sliding standard," the commenter is referring to the fact that the required sulfur reduction efficiency for plants over 5 LT/D varies with the sulfur feed rate and the acid gas ratio (i.e., as the ratio of volume percent H_2S to CO_2 increases, the sulfur recovery efficiency increases). Thus, the required recovery efficiency for a given plant may vary according to changes in the sulfur feed rate and acid gas ratio. However, the degree of variability will depend on the individual plant. In many instances, the sulfur feed rate and H_2S concentration are expected to be essentially constant for long periods.

Representatives of the natural gas processing industry have stressed that sulfur feed rate and acid gas ratios are directly related to efficiencies. The sliding standard accommodates this relationship in that it considers the dependency of emission reduction efficiency on the mass flow rate and concentration of H_2S in the acid gas stream at a given plant. A uniform mass or concentration limit format (specifying a single mass value per day or a single value for required efficiency) would not reflect the fact that achievable reduction efficiencies are a function of the factors cited above. The ability of an owner or operator to comply with a single value standard on a continuous basis could not be assured.

The Agency believes that the emission reduction efficiency format for determining compliance with the standards is reasonable. The daily sulfur recovery determinations can be easily plotted on a graph either manually or with automated data reduction equipment. Such graphs would provide the basis for excess emission reports sent to the enforcement agency. State enforcement personnel would not need to make plant visits to inspect plant records under normal circumstances.

The equations used to determine efficiency levels represent continuous functional relationships between efficiency levels required and the operational conditions which vary from plant to plant (i.e., sulfur feed rate and mole percent H_2S). Variations in acid gas ratios do not significantly affect the calculation of reduction efficiency. The calculation of the required efficiency is based on actual operating conditions each day. The required efficiency is then compared to the actual efficiency enabling timely adjustments.

2.12 MONITORING AND PERFORMANCE TEST REQUIREMENTS

Comment: Nine commenters (IV-F-1, IV-D-16, IV-D-18, IV-D-19, IV-D-22, IV-D-23, IV-D-28, IV-D-29, and IV-D-31) stated that small plants, especially those in remote areas, do not have staff on site 24 hours per day and therefore it would be difficult to obtain twice daily measurements for calculating sulfur removal efficiency. One commenter (IV-D-19) suggested that when "R" (achieved sulfur emissions reduction efficiency) is greater than a midpoint, "M," between "Z" (required sulfur emission reduction efficiency) from equation 1 and "Z" from equation 2 in the standard, "R" should be calculated once a month. When "R" is less than or equal to "M," "R" should be calculated once a week.

Another commenter (IV-D-27) recommended that "R" be calculated on a weekly basis because the 12-hour interval requirement creates additional gauging, reading, and calculations at considerable expense and that measurements, other than those necessary for operational control, are frequently taken no more often than every 24 hours and perhaps not at all on holidays and weekends.

The commenter also stated that emission reduction efficiency is maintained by control of the H_2S/SO_2 ratio. Many plants take spot readings of total emissions to confirm recoveries.

In the opinion of the commenter, the imposition of a specific time interval for calculation is unwarranted and unnecessary and each plant may have valid reasons to use other schedules. He claimed that selection of a specific calculation time interval will have no effect on emission reduction efficiency. He stated further that the recovery determined in such intervals will be very misleading for all the sub-dewpoint adsorption processes, CBA, Sulfreen, MCRC, etc. Most often, the units will not complete a full cycle within 12 hours. Sulfur production during one 12-hour period may be substantially lower than that shown for the next 12-hour period. The reporting system could thus erroneously label alternate periods as periods of excess emissions.

Response: The Agency has reviewed the requirements for performing readings every 12 hours. The 12-hour interval was selected to give results comparable to those measured during the 12-hour initial performance test. The Agency performed tests which show that the variation of 12-hour average results, as compared to 24-hour average results, is not large. Since the results of 24-hour measurements are expected to be essentially the same as 12-hour measurements and since normal practice of sulfur recovery plant operators is to determine the production rate on a daily basis, the requirement has been changed to allow calculation of recovery efficiency on a 24-hour basis.

The purpose of determining achieved sulfur emissions reduction efficiency "R" on a regular basis is to ensure proper operation and maintenance. Monthly determinations of "R" would not provide performance trend data required to ensure proper operation and maintenance of the sulfur recovery equipment.

The selection of which 24-hour interval to use is left to the discretion of the plant owner or operator. However, the interval must be consistent (i.e., the same time each day). (Note: The regulation, §§60.646(b)(5) and 60.647(b)(1), has been changed to eliminate the specific "midnight" and "noon" clock intervals for the determination of "R.") The adsorption processes will not affect the calculation of efficiencies on a 24-hour basis. The Agency regards this 24-hour interval as a reasonable interval to ensure proper operation and maintenance.

Comment: Three commenters (IV-D-13, IV-D-27, and IV-D-29) stated that gauging the sulfur pit or measuring sulfur production by any method over a short-term (less than 24 hours) period is inaccurate. According to commenter IV-D-13, this is due to liquid sulfur entrainment in the catalyst beds, a normal operating phenomenon, which results in wide fluctuations in short-term production rates because of loading and unloading of liquid sulfur in catalyst beds. The commenters also stated that accurate sulfur tank volume measurements are not always attainable because of variations in the thickness of sulfur cakes on the wall caused by temperature changes. Because of such characteristics inherent in the sulfur recovery process, the commenters claimed that short-term production test requirements are not appropriate.

One commenter (IV-D-29) added that production rate data are not collected during weekends because of the inaccuracy of pit gauging. He stated that the operator relied on monitoring the H_2S/SO_2 ratio with a ratio controller to maintain plant efficiency.

Three commenters (IV-F-3, IV-D-27, and IV-D-29) questioned the 2 percent accuracy of sulfur production measurements, as stated in §60.646(b)(2).

Response: As discussed in the previous response, the Agency has changed the sulfur recovery measurement interval from 12 hours to 24 hours. The 24-hour interval should alleviate the problems associated with the fluctuations in production rates resulting from liquid sulfur entrainment in the catalyst beds.

Sulfur cake buildup is not expected to pose a significant problem. The Agency made several contacts which indicated that sulfur tanks are either located below ground or are insulated. In both instances, the buildup of sulfur cake is minimized. In these contacts, cake buildup was not identified as a significant concern.

The source of the questioned ±2 percent accuracy estimate for sulfur production measurement methods is a technical report, "Capability of the Modified Claus Process," developed by Western Research and Development Corporation (Docket Entry II-I-41). Based on the nature of the measurement method, EPA believes that the ±2 percent uncertainty estimate is reasonable. The expected method of measurement is to measure the depth of liquid sulfur in the storage tank at the beginning and end of the measurement period. (Note the proposed 12-hour period is being changed to a 24-hour measurement period.) The depth measurement should be accurate to within at least plus or minus 0.5 centimeters. On a typical sulfur pit (3 x 6 x 5 meters) for a sulfur recovery plant producing 30 Mg/D of sulfur, this would amount to a sulfur mass measurement error of about plus or minus 0.6 percent over a 24-hour compliance period (Docket Entry IV-B-2). This measurement, with subsequent calculations based on tank geometry and sulfur density, should yield a total error of no more than ±2 percent.

Monitoring requirements are designed to ensure proper operation and maintenance at all times. Deviations from the required monitoring schedule on weekends would be contrary to the intent of the standards.

Comment: Twelve commenters requested that smaller plants, unattended for more than 12 hours per day, be exempt from the requirements for continuous SO_2 monitoring. One commenter (IV-D-19) suggested a 10 LT/D cutoff. Commenter IV-D-23 suggested 20 LT/D. Two commenters (IV-D-22 and IV-D-25) suggested 50 LT/D. Commenter IV-D-18 suggested 100 LT/D. Commenters IV-F-5, IV-D-11, IV-D-13, and IV-D-29 recommended that the cutoff be 800 LT/D. Commenter IV-D-27 suggested 1,000 LT/D. Commenter IV-D-20 recommended that plants less than several hundred LT/D be exempted from continuous SO_2 monitoring and commenter IV-D-30 suggested that only relatively large plants be subject to continuous monitoring requirements. These commenters stated that only the larger plants were staffed with technical operating and maintenance personnel.

Response: Two methods of calculating emission reduction efficiency are considered appropriate for these standards. One method involves continuously measuring SO_2 emissions and calculates efficiency by comparing the amount of sulfur recovered to the sum of the sulfur emitted and the liquid sulfur recovered [sulfur recovered ÷ (sulfur emitted + sulfur recovered)]. The second method does not involve measuring emissions; instead efficiency is calculated by comparing the amount of sulfur recovered to the amount of sulfur entering the sulfur recovery unit (sulfur recovered ÷ inlet sulfur). The first of these methods provides the most accurate determination of efficiency and, since emissions would be monitored on a continuous basis, provides the owner/operator and enforcement personnel with an ongoing indication of performance of the sulfur recovery unit. For a plant achieving 94 percent sulfur removal efficiency, the efficiency calculations using the emission measurement approach are estimated to have about a ±0.6 percent error. Calculations using the second method are estimated to have an error of about ±5 percent.

The accuracy of the emission monitoring method makes it the preferrable method in most cases. However, the Agency recognizes that operating these continuous emisson monitors may necessitate the presence of a trained instrument technician on a part-time, or, in some cases, a full-time basis. The Agency has considered the costs of these technicians in estimating costs and evaluating the incremental cost analysis for the sulfur recovery technologies and regards these costs to be reasonable. However, the Agency recognizes that smaller plants pay a proportionately higher cost for monitoring equipment (relative to total plant costs) than larger plants and gain a proportionately small benefit in emission reduction from the more accurate monitoring method.

The Agency performed an analysis, which simulated the additional emission reduction resulting from the more accurate emission/production method compared to the inlet/production method. The potential additional emission reduction was evaluated along with the additional costs of the stack monitoring equipment (including a full-time trained technician and maintenance costs). Based on this analysis, the Agency has exempted plants with sulfur feed rates less than 150 LT/D from the requirements for continuously monitoring SO_2 emissions. These plants are required to calculate emission reduction efficiency on a daily basis, but they are required to measure inlet sulfur once every 24 hours instead of continuously monitoring stack gas SO_2 concentrations.

For plants ≧150 LT/D, the Agency will continue to require continuous emission monitoring to maintain the accuracy afforded by that method.

Comment: Eleven commenters (IV-F-2, IV-F-3, IV-F-5, IV-D-8, IV-D-19, IV-D-20, IV-D-25, IV-D-27, IV-D-28, IV-D-29, and IV-D-31) questioned the economical justification of continuous SO_2 monitors. Specifically mentioned were installation and maintenance costs for the monitoring system and labor costs. Costs presented by commenters included:

- (IV-D-25): Purchase and installation of a SO_2 continuous emission monitor on a 160 LT/D SRU incinerator costs were over $140,000.
- (IV-D-29): Commenter cited a report stating $100,000 to $150,000 actual cost estimate for a continuous SO_2 monitor installed at a Chevron refinery.
- (IV-D-19): Commenter reported that three companies had total installed costs of $46,000 (1979 dollars), $85,000 (1983 dollars), and $144,000 (1983 dollars) for continuous SO_2 monitors.
- (IV-D-8): Commenter reported that in the first 2 months of 1984, 90 man-hours ($2,130) were spent on scheduled maintenance and 165 man-hours ($4,236) were spent on trouble calls for SO_2 monitors.

- (IV-D-31): Commenter said that in 1983 his company spent $30,000 for parts and outside technicians to repair one monitor and that company labor dedicated to that monitor exceeded $13,000.

Response: The Agency has taken into consideration the cost of SO_2 emission monitoring systems found in the literature, from vendors, and through field experience with similar monitoring systems. A system to meet proposed monitoring requirements would include a device to measure sulfur, a stack gas velocity flow meter, and a data integration instrument. If a flue gas oxidation unit is used, an SO_2 analyzer would also be included. In the Volume I BID, an investment cost of $45,000 was estimated based on data provided by Western Research and Development Corporation (Docket Entries II-E-28, II-E-29, and II-E-30). The annualized operating cost, $40,000 per year, was also derived from these data.

The Agency has reevaluated these costs and concluded that they continue to be reasonable estimates of the cost of installing and operating an in-stack continuous SO_2 monitor. The $40,000 per year estimate includes $17,000 per year for operating technician labor, $5,000 per year for maintenance, and $18,000 per year capital charge (based on a 3-year monitor life assumption). The EPA also developed high and low estimates to reflect the range of costs that could be expected. The high estimate is $65,000 per year and the low estimate is $33,000 per year (see Docket Entry IV-B-4). For plants with feed rates ≥150 LT/D, these costs are considered reasonable in view of the additional emission reduction that would be achieved with continuous monitors.

One report, prepared by Radian (Docket Entry IV-A-2) and referenced by commenter IV-D-29, does cite a cost of $100,000 to $150,000 as an estimated cost of a fully installed unspecified operational SO_2 continuous emission monitoring system. One of the authors in this report was contacted for a breakdown of these costs. He stated that these figures included hardware, installation, training, start-up costs, and other in-house expenses, and that the estimate represented that company's estimate of what it would cost to get the system working well. Several of these total cost components would be considered "overhead" by most plants and, thus, would not be included in most estimates of continuous monitoring systems. It should be noted that other continuous emission monitoring costs cited by other companies surveyed in the same report closely match those estimated by the Agency.

To better understand the significance of the reported operating costs for monitors, commenter IV-D-8 was contacted to determine the number of monitors included in the aggregate cost data provided (Reference Docket Entry IV-D-14). The cost data were found to include costs for tail gas monitors for four sulfur recovery units in separate facilities. Therefore, assuming the costs for maintenance and trouble calls presented by the commenter of $2,310 and $4,236, respectively, are representative of a 2-month period for four monitors, the yearly cost for a single monitor would be approximately $9,800. The $40,000/year estimate in the BID for the proposed standards included $5,000/year for maintenance and $17,000/year for labor for routine and nonroutine service. The commenter's $9,800/year estimate is in line with these estimates.

Commenter IV-D-31 was contacted for clarification of expenditures for parts and outside labor for monitor repair (see Docket Entry IV-E-2). It was determined that the monitor was installed in 1978 and the system overhauled in January of 1980. The $30,000 expenditure in 1983 apparently represents maintenance and/or replacement costs for a 5-year-old system. Given the overhaul in early 1980, it would be reasonable to prorate the $30,000 over a period of 4 years, or $7,500 per year. Commenter's $13,000 in 1983 for company labor is in line with the Agency's $17,000 per year estimate. Commenter apparently elected to repair, rather than replace, the monitoring system. Given the age of the monitoring system and the distribution of expenses over the corresponding time frame, these expenditures are consistent with the Agency's estimates.

The Agency recognizes that exceptions to the estimated costs will occur. However, the preponderance of data supports the estimates and the Agency regards the basis for these estimates as reasonable.

Comment: Eight commenters (IV-F-2, IV-F-5, IV-D-10, IV-D-13, IV-D-24, IV-D-27, IV-D-28, and IV-D-29) questioned the accuracy, reliability, and availability of SO_2 continuous monitors. One commenter (IV-D-13) stated that the uncertainties (volumetric flow rate, molecular weight, and water content of the stack gas) associated with continuous monitoring are substantially greater than the ±0.6 percent value reported in the proposed standards. He recommended that the sulfur recovery equation in 40 CFR 60.642(a) be reevaluated to address this relative inaccuracy.

Two of the commenters (IV-F-5 and IV-D-13) stated that continuous SO_2 monitors are unproven technologically, that they require excessive amounts of maintenance and specially trained employees, and that these employees are not available at remote locations. Commenter IV-D-24 quoted a Radian study which reported only two continuous SO_2 monitors in petroleum extraction industry sulfur recovery plants, both of which were located in large plants. The commenter reported that the study indicated "about 75 percent of an instrument technician's time is used for the operation and maintenance of . . . one analyzer." The commenter also quoted the Volume I BID (pg. D-7) which indicated that no Agency field evaluations were conducted and that only vendor information was available from which to judge the monitor's accuracy, reliability, and operability. The commenter concluded that there are not sufficient data available at the present time to warrant the use of continuous SO_2 monitors.

Commenter IV-D-29 stated that the Agency relied on vendor information and literature sources (Volume I BID, pg. D-7) for data concerning availability, operation, and maintenance for continuous SO_2 analyzers without providing citations to the information. He also referenced the fact that the Agency had "not conducted field evaluations of these systems" and also did not provide laboratory testing data of continuous analyzers.

One commenter (IV-F-2) stated that only one supplier of SO_2 continuous monitors is known to him.

Response: Continuous SO_2 monitoring is required to ensure that sulfur recovery operations are properly operated and maintained on a continuous basis. At the time of development of the Volume I BID, the Agency did rely on vendor information and literature sources for data concerning SO_2 analyzers because that was all that was available. Since that time there have been further studies conducted for the Agency (Docket Entries IV-A-1 and IV-A-3). These studies verify that SO_2 continuous emission monitors (CEM's) are in use at many refineries and natural gas processing plants. The number of CEM's identified is sufficient to establish the commercial availability and applicability of CEM's. Commercially available monitors show good (e.g., generally greater than 95 percent up-time) performance.

In response to the commenter's (IV-F-2) statement that there was only one supplier, at least four vendors of continuous SO_2 monitors are known to EPA. These include Western Research and Development, duPont, Lear-Siegler, and Dynatron.

The ±0.6 percent uncertainty estimate was based on a conservative estimate of uncertainty in the emission monitoring method (Docket Entry II-I-41). The ±0.6 percent uncertainty value represents a combination of uncertainty values associated with the measurements involved in the calculation of sulfur recovery efficiency and not the uncertainty associated with the SO_2 emissions measurement alone. Literature from SO_2 mass monitoring equipment vendors (Docket Entry II-D-34) indicates that such systems exhibit accuracy of ±5 percent. The Agency assumed an accuracy of ±10 percent in this measurement system. Thus, the ±0.6 percent uncertainty in the calculated sulfur recovery efficiency should be conservative.*

The Agency recognizes that operation and maintenance of continuous emission monitors may require trained instrument technicians. The costs for trained technicians were included in the Agency's estimates of monitoring costs. For a discussion of the revision of the standards to exempt plants <150 LT/D from continuous monitoring requirements, refer to the responses earlier in this section.

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*The 0.6 percent uncertainty estimate is derived from the measurement uncertainties of the sulfur production rate (±2%) and the emission rate (±10%) used in calculating the sulfur recovery efficiency. The derivation is made consistent with a standard propagation of error formula for equations of the form S/(S+E), which is the formula used to calculate the sulfur recovery efficiency. (See Docket Entry IV-B-7 for specific information about the propagation of error formula and the relationship between the uncertainties of the measured sulfur production rate, the measured emission rate, and the calculated sulfur recovery efficiency.) Intuitively, one might not expect the 0.6 uncertainty to result from the higher 2 and 10 percent uncertainties of the measured values. However, this results from the form of the propagation of error formula and the relative magnitudes of the sulfur production rate (S) and the emission rate (E) for plants with sulfur recovery efficiencies in the 90 to 99 percent range.

Comment: One commenter (IV-F-3) stated that industry should not be required to achieve the high level of accuracy and reliability of SO_2 monitoring in the proposed standards until monitoring equipment is available which can adequately respond to the wide day-to-day variations in plant operating conditions. The commenter claimed that the velocity of the incinerator stack gases can vary up to 400 percent with concomitant static pressure changes of up to 200 percent. For these reasons, the commenter stated that measured emission results would be inaccurate.

Response: Information gathered by EPA does not show the wide variation in incinerator stack gas flows and static pressure changes reported by the commenter. Research performed by the Western Research and Development Corporation shows that incinerator stack gases vary between about 75 and 110 percent (see Docket Entry II-I-68). The stack gas velocity does not vary in proportion to the sulfur production capacity because at lower production rates the feed and combustion in feed rates to the incinerator are increased to maintain the temperature at a high enough level to oxidize the residual TRS to SO_2. Combustion gases from the additional feed partially affect the decreased stack gas volume from decreased sulfur production volume. When the system stack is designed to accommodate typical flow velocities, commercially available S-type pitot tubes are capable of accurately measuring up to 400 percent variation in stack gas velocity. Therefore, accurate emission measurement results are possible with the velocity variations cited by the commenter.

Comment: The commenter (IV-F-2) stated that the continuous monitoring requirements of paragraph 60.646 are difficult to attain because of the corrosive nature of hot stack gas and the lack of choices in suitable continuous monitors for flow rate. The commenter recommended the following alternate monitoring requirements for stack gas flow rate and stack gas SO_2 content to determine SO_2 emissions.

1. Continuous monitoring of SO_2 and O_2 in stack gas emitted to the atmosphere during initial performance test.
2. Annual performance tests of sulfur recovery units analyzing all inlet and outlet streams, measured over a 24-hour period and submittal to EPA of sulfur recovery measured.

3. Correlate SO_2/O_2 from test data and/or calculations to measure sulfur recovery to allow estimation of sulfur recovery in interim periods between tests.

The commenter also provided alternative procedures for quarterly or semiannual sulfur recovery determinations, which could be performed with usual plant laboratory equipment and could be conducted by in-plant personnel. The method was quoted as being accurate to within plus or minus 0.5 to 1.0 percent of the sulfur recovery efficiency.

Response: The incinerator stack gas is not expected to be as corrosive as indicated by the commenter because the temperature of the incinerator stack gases is maintained in most instances well above the dew point. Incinerator stack gas temperatures of the units tested by the Agency ranged between about 900 and 1150°F. Assuming typical moisture concentration in the stack gas of 25 percent and an upper boundary SO_2 concentration of 40 ppmv, the dew point can be calculated to be about 315°F (see Docket Entry IV-B-5). The calculation supports the position that the dew point likely will not be reached and the environment in the incinerator stack, therefore, should not be corrosive. With the use of heated, corrosion resistant sample lines and heated monitoring equipment, temperatures in the monitoring system can be maintained above the dew point and corrosion problems in this equipment similarly can be avoided.

During development of the proposed standards, the Agency considered the alternative method for continuous monitoring proposed by the commenter, which correlates SO_2 and O_2 levels to efficiency. The Agency rejected this approach because the SO_2/O_2 correlation must be made for each individual sulfur recovery unit inlet stream condition. Because of the fluctuations in stream conditions, extensive testing would be necessary to establish a valid SO_2/O_2 correlation. Therefore, the Agency decided against this alternative method.

The commenter's suggestions for alternative monitoring methods were reviewed by the Agency. The Agency believes that the continuous monitoring strategies outlined in the proposed preamble, coupled with daily emission reduction efficiency verifications, provide a more realistic and more accurate account of the operating status of the plant. Checking sulfur recovery efficiency with performance tests once a year as suggested by the commenter would not provide any indication of

Response: The initial performance tests require specialized equipment and personnel experienced in stack sampling and, therefore, may warrant the use of contract firms. This initial test is required only once. Method 6 performance tests are required for SO_2 emissions measurements during the initial performance test. Other than this start-up requirement, Method 6 tests are not required by the standards. Quarterly measurements (now, daily) are limited to measurements of H_2S concentration and volumetric flow rate of the acid gas feed to the sulfur recovery plant. Plant personnel are capable of performing these measurements. The expense involved in the quarterly procedures has been considered in the cost analysis and is considered by the Agency to be reasonable.

In accordance with the General Provisions (40 CFR 60.8), alternative methods may be approved providing they are equivalent to the methods listed in the standard.

Comment: Two commenters (IV-D-18 and IV-D-29) recommended that continuous TRS monitoring requirements [60.646(b)(4)] be deleted from the standard because TRS monitoring instruments are not commercially available and are not necessary for accuracy. Commenter IV-D-29 questioned the statement made by the Agency in the Volume I BID (pg. D-7) that a total reduced sulfur analyzer would be used to evaluate total sulfur emissions. He stated that omission of TRS monitoring would result in a 0.02 percent difference in plant efficiency (no specific data were given) and claimed that the Agency agreed that this difference was acceptable because measurement of sulfur production rate is accurate only within 5 percent (49 FR 2665).

Response: Use of TRS monitors is required by the standards only if compliance with §60.642(a) or (b) is accomplished by use of a reduction control system not followed by a continually operated incineration device. It should be noted that use of these monitors will not be required until either the Agency determines the applicability of the existing Performance Specification #5 to natural gas processing plants or promulgates a new performance specification for TRS monitors in natural gas processing plants.

how the plant is functioning in-between tests. It also would fail to provide the plant operator with data indicating possible process changes needed to respond to day-to-day and month-to-month changes in acid gas characteristics to maximize plant efficiency. Therefore, an annual check would not assure proper operation and maintenance of the plant. The continuous monitoring and the daily check on emission reduction efficiency do provide these data.

Comment: The commenter (IV-D-10) recommended that the continuous emission monitoring requirement be deleted because periodic performance tests would be adequate to determine compliance.

Response: The continuous emission monitoring requirements are intended to assure proper operation and maintenance of the sulfur recovery equipment on a continuous basis and are not a measure of compliance. The monitoring requirements are intended to provide both owners/operators and enforcement personnel an accurate indication of daily performance of the recovery system. Based on these daily data, plant personnel can make adjustments in operation to ensure that required recovery efficiencies are maintained. Enforcement personnel will use these data to decide whether problems exist which may warrant a compliance test. A requirement for a periodic compliance test alone would not provide sufficient information to determine whether the systems are being properly operated and maintained on a continuous basis.

Comment: Nine commenters (IV-F-1, IV-D-13, IV-D-18, IV-D-19, IV-D-23, IV-D-27, IV-D-29, IV-D-30, and IV-D-31) regarded the quarterly verification requirements as excessive. The commenters mentioned that outside contractors would be required to perform the monitoring, and that quarterly testing using Method 6 would be expensive. Commenter IV-D-27 suggested alternate methods, such as ultra-violet light, length-of-stain tubes, and gas chromatography, for obtaining intermediate data. Commenter IV-D-29 stated that ratio controllers are used to monitor the Claus process and implied that these ratio controllers could be used as an alternative. He said that the ratio controller is periodically reset using the Tutwiler or similar procedure. This commenter also claimed that each quarterly test, as required by the standard, would cost $25,000.

Response: The initial performance tests require specialized equipment and personnel experienced in stack sampling and, therefore, may warrant the use of contract firms. This initial test is required only once. Method 6 performance tests are required for SO_2 emissions measurements during the initial performance test. Other than this start-up requirement, Method 6 tests are not required by the standards. Quarterly measurements (now, daily) are limited to measurements of H_2S concentration and volumetric flow rate of the acid gas feed to the sulfur recovery plant. Plant personnel are capable of performing these measurements. The expense involved in the quarterly procedures has been considered in the cost analysis and is considered by the Agency to be reasonable.

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These monitors are available from a number of manufacturers (e.g., Applied Automation, duPont, Bendix). Users of these continuous emission monitors at sulfur recovery units in refineries and natural gas plants have been identified in an EPA study (Docket Entries IV-A-1 and IV-A-3).

In the absence of an operating incinerator, TRS monitoring data are required to determine sulfur emission rates. For recovery units with an operating incinerator, SO_2 monitoring data provide sufficient sulfur emission data and TRS monitors are not required in such cases. It would be only under such cases in which a TRS monitor would be used in addition to an SO_2 monitor on a unit employing a properly operated incinerator that the calculated efficiency would increase by only about 0.02 percent. The Agency agrees that the additional accuracy provided by a TRS monitor on a system with a properly operated incinerator is not warranted.

Comment: The commenter (IV-D-18) recommended that §60.645(a)(1) be deleted. No reason for this recommendation was provided.

Response: Commenter is referring to the reference method (Method 1) for velocity traverse points selection. The volumetric flow rate is necessary to calculate the sulfur mass rate. Volumetric flow rate is calculated using the average velocity in the duct or stack. The average velocity is determined by Reference Method 2. Since this procedure is based on the use of a pitot tube that measures velocity at point locations in the flow cross section, multiple measurement points are necessary to determine the average velocity for the flow area. Method 1 is a formal procedure for selecting these measurement points.

Comment: Commenter IV-D-30 claimed that there was no real reason to perform Method 6 (SO_2) and Method 16A (TRS) separately for oxidation type control systems because the two results are summed to determine sulfur emissions. Specifically, Method 6 could be utilized with the addition of the combustion tube apparatus as described in Method 16A. This procedure would result in all sulfur species being oxidized and collected while reducing the testing time by 50 percent.

Response: Method 6 and Method 16A must be performed separately for systems using an incinerator because the standards require the determination of the ratio of SO_2 to total sulfur for the purpose of ensuring complete oxidation of sulfur compounds to SO_2. The commenter's suggestion that Method 6 be used with the combustion tube apparatus described in Method 16A would be appropriate if determination of total sulfur were the only requirement. However, the Agency has not evaluated this procedural variation to determine if a combined measurement would yield equivalent results, and therefore, there is no basis to promulgate a reference test method in Appendix A using this procedure. An owner or operator may request that the Administrator approve the use of this alternate technique under the provisions of 60.8(b) if sufficient supporting information is provided to demonstrate the adequacy of the proposed technique for determining compliance. At this time, the Agency does not regard the requirement for a Method 6 and a Method 16A test for these one-time performance test requirements as excessive.

Comment: The commenter (IV-D-30) claimed that Performance Specification #2 of the general NSPS rules for continuous SO_2 monitors is applicable only to instruments which generate concentration values. Since the proposed standard requires continuous monitoring of mass emission rates, the commenter claimed that an adjustment to the performance specifications procedures is needed to account for error in continuous determination of flow rate and specifically, the relative accuracy specification should be modified. The commenter recommended that the Agency review the issue to eliminate any inconsistency between the type of continuous monitor required by the proposed NSPS and the criteria of Performance Specification #2.

Response: The Agency recognizes that Performance Specification #2 pertains to measurement results expressed as concentration values. However, when SO_2 concentration measurements are made in conjunction with a properly installed, operated, and calibrated stack gas flow meter, the relative accuracy requirements can be met. It should be noted, however, that the instrument must be operated within its proper design range. Significant errors can result from the operation of a flow meter outside its specified range. The Agency assumes that appropriate instrumentation is being used. Therefore, no adjustment will be made to Performance Specification #2 to accommodate these standards.

Comment: The commenter (IV-D-18) requested that a minimum of fifteen 1-hour averages be used to compute each 24-hour average emission rate "E," instead of nine 1-hour averages to compute a 12-hour average.

Response: The requirement for nine 1-hour averages to compute a 12-hour average reflects a 75 percent data capture requirement. The EPA requirement is at least one data point per 15 minutes and two 15-minute points for calculation of a 1-hour average. Experience indicates that this is reasonable for SO_2 monitors and allows sufficient time for adjustments to the monitor or other operations that preclude 100 percent data availability. The standards have been revised to allow calculation of recovery efficiency on a 24-hour basis. In keeping with the 75 percent data capture requirement, 18 1-hour averages will be required to compute each 24-hour average.

Comment: The commenter (IV-D-18) recommended that requirements of §60.646(b)(5) be waived when instrument malfunctions limit the sulfur emission data collection, provided the owner/operator makes reasonable efforts to maintain and operate the monitoring instrument.

Response: Requirements of §60.646(b)(5) cannot be waived but data for periods of instrument malfunction should be noted as not available for recordkeeping purposes. Sections 60.7(b) and (c)(2) of the General Provisions provide for such periods of breakdown or repair and require identification of the malfunction nature, cause, and corrective action taken.

Comment: The commenter (IV-D-18) recommended deleting §60.647(b)(2) and inserting the statement, "Any 24-hour period during which the flare or incinerator is operated less than 12 hours."

Response: The Agency disagrees with the commenter's recommendation to delete §60.647(b)(2) because the provision is necessary to ensure complete oxidation of sulfur compounds to SO_2. However, in response to other comments, this section has been revised to replace the temperature requirement with an alternate provision to ensure oxidation of sulfur compounds to SO_2.

The commenter's proposed definition of excess emissions would make it possible for a sulfur plant to operate without incineration or flaring for up to half the time without a report of excess emissions. The Agency rejects this suggestion.

2.13 RECORDKEEPING AND REPORTING REQUIREMENTS

Comment: Two commenters (IV-F-2 and IV-D-18) suggested annual or semiannual reporting instead of quarterly reporting to relieve what are, in their opinion, excessive reporting requirements.

Comment: The commenter (IV-D-18) claimed that the monitoring, recordkeeping, and reporting requirements were excessive for small to medium sized plants and suggested that requirements could be reduced and still achieve SO_2 emission reductions.

Specifically, the commenter recommended that:

1. Plants handling less than 20 LT/D be exempted from all requirements except in-house records to justify the exemption.
2. Plants between 20 and 100 LT/D should be required to maintain in-house records of daily sulfur production, quarterly gas analysis, and annual calculation of sulfur recovery efficiency.
3. Plants larger than 100 LT/D should be required to record daily sulfur production, quarterly gas analysis, and calculation of sulfur recovery efficiency, and should report these data to the Administrator annually. The commenter also stated that continuous monitoring may be required for such facilities.

Comment: The commenter (IV-D-22) requested that facilities less than 50 LT/D should be exempt from continuous monitoring and recordkeeping requirements because these plants are operated with very small staffs and the recordkeeping and reporting would be burdensome with little benefit to the environment.

Comment: The commenter (IV-D-28) claimed that the recordkeeping and reporting requirements of the standard were excessive and estimated they would require 160 man-days per year per plant.

Comment: Three commenters (IV-D-16, IV-D-22, and IV-D-28) claimed that many small remotely located plants are staffed less than 12 hours per day. The commenter stated that recordkeeping, reporting, and instrumentation requirements are all excessive and may cause many small fields to be uneconomical to produce.

Response: The reporting requirements outlined in the proposed standards are not considered by the Agency to be excessive. During the first 3 years of implementation, the average industry-wide labor burden was estimated to be 8.4 person-years per year, based on an average of

12 respondents per year. These labor estimates are considered by the Agency to be reasonable. However, in response to the concerns presented by representatives of small remote plants, the standards have been revised to require sulfur measurements every 24 hours instead of the 12-hour frequency required in the proposed standards.

Also, the quarterly period for reporting excess emissions has been revised. These reports will now be required semiannually instead of quarterly.

Comment: The commenter (IV-D-9) stated that plants with design capacities less than 1 LT/D should be exempted from recordkeeping and reporting requirements which require that an analysis of the facility's design capacity be retained for the life of the plant. The commenter contended that the requirements were too stringent for small, isolated plants and that the document may easily be misplaced during the facility's lifetime. Another commenter (IV-D-18) requested that the portion of the regulation [60.647(c)] dealing with recordkeeping and reporting requirements for plants less than 1 LT/D be deleted.

Response: Documenting the design capacity of a plant is required to determine the applicability of the standards. If the design capacity is less than 2 LT/D, then no further analyses are required. This single determination has not been found by the Agency to be excessive. Proper business procedures should allow for the safekeeping of this and other company records. Note also that these records need not be kept at the plant site.

The average industry-wide labor burden for recordkeeping and reporting requirements for plants with design capacities less than 2 LT/D during the first 3 years of implementation of the standards was estimated to be 18 person-hours per year, based on an average of 6 respondents per year. These estimates and burdens are regarded as reasonable by the Agency.

Comment: The commenter (IV-D-17) claimed that the data gathering and recordkeeping requirements of the standard were extensive and that enforcement efforts using a large volume of past records would lack the clarity and relevance provided by a recent stack emission test. For this reason, the commenter favored an emission rate standard for enforcement purposes. The commenter stated that recordkeeping and calculated performance were useful tools in indicating the need for stack testing. The commenter claimed that the records were to provide demonstration of compliance.

Response: The basic concern raised by the commenter is that data gathering and recordkeeping requirements associated with the continuous emissions monitoring requirements in §60.646 are excessive and inappropriate for determining compliance with the standard. The commenter has misinterpreted the purpose for the monitoring and associated recordkeeping requirements. These provisions are not for determining compliance but rather they provide an indication of whether or not an affected facility is being properly maintained and operated on a continuous basis. These data assist enforcement officials in the decision of whether or not a performance test is necessary to determine compliance. The Agency is not requiring performance tests on a periodic schedule because of cost considerations. Rather, the Agency established what is believed to be the minimum monitoring and recordkeeping requirements needed to ensure proper operation and maintenance and to provide enforcement agencies with an indication of compliance status.

The allowable emission rate format favored by the commenter was considered in the development of the standard, as discussed in the preamble (49 FR 2663). Allowable emission or mass emission rate format is expressed in pounds per hour and parts per million by volume that apply uniformly to all facilities within a range of sulfur feed rates (sizes) and H_2S concentrations. If the allowable emission rate format was used, the standards would have to specify numerous mass rate limits corresponding to efficiencies achievable with BDT. Either of these formats would establish required emission reduction efficiencies applicable to various plant sizes. Large plants would have to achieve high reduction efficiencies while smaller plants within the same range would have to achieve increasingly lower reduction efficiencies to meet the same limit. This would present a situation in which smaller plants would not have to install BDT or larger plants would require technologies with performance capabilities exceeding those of BDT.

Because the format of the standard needs to reflect the variation in the emission reduction efficiencies achievable by the selected BDT, the proposed standard takes the form of an equation that calculates the required emission reduction efficiency (or sulfur recovery efficiency) for each specific plant type based on the two characteristics of the acid gas (i.e., the mass flow rate of acid gas and the concentration of H_2S in the acid gas). The equation calculates required emission reduction efficiencies that closely match the efficiencies achievable with BDT. The result is a standard that ensures the application and the proper operation of BDT at new facilities. For this reason, the Agency regards the reduction efficiency format as the most appropriate for the standard.

Comment: The commenter (IV-D-23) recommended that only one quarterly report be submitted either to a State or Federal agency for compliance with all air pollution regulatory requirements including PSD, NSPS, and any other applicable regulations.

Response: If, in delegating enforcement authority to a particular State under Section 111(c) of the Act, EPA approves the reporting requirements adopted by such State, then the affected sources within the State may comply with the State requirements in lieu of the Federal requirements.

2.14 DIFFERENCE IN STATE AND NSPS REQUIREMENTS

Comment: The commenter (IV-F-4) expressed concern over the differences in conversion efficiencies required by the Texas Air Control Board and those of the proposed regulation and the possible net increase in SO_2 emissions that may result from NSPS promulgation and enforcement. Another commenter (IV-D-17) stated that the NSPS appeared to be more lenient than the current Texas Air Control Board appraisal of best available control technology. The first commenter provided plant-specific data on 14 cases that indicated that differences in required conversion efficiencies would be generally in the 2 to 4 percent range. One particular case had a 20 percent difference in conversion efficiency. An overall increase in SO_2 emissions in that State would total 22,800 tons per year, if the proposed standards are adopted, according to Texas Air Control Board estimates.

Response: The required sulfur recovery efficiencies in the standards are designed to be applicable nationwide. Federal regulation requirements must be achievable by all affected facilities, irrespective of local air quality conditions. Standards with a degree of uniformity are needed to avoid situations where some States may attract industries by relaxing standards relative to other States. The NSPS serve as a minimum requirement to reduce emissions from each designated source category on a nationwide basis and are developed considering factors such as incremental cost effectiveness.

Some States may require emission reductions more stringent than NSPS in order to meet that State's air quality goals. Section 116 of the Act permits these States to establish more stringent standards. As a result, factors considered in NSPS development (e.g., incremental cost effectiveness) may be different for the State standards.

Comment: The commenter (IV-D-7) expressed his opinion that the proposed standards are too lenient, given the wide range of available sulfur control technologies. The commenter recommended adoption of Regulatory Alternative IV or, preferably, Alternative V instead of III as in the proposed standards. The commenter stated that technologies similar to Alternative V are currently required in Michigan and are economically feasible.

Response: The Agency selected the regulatory alternative based primarily on incremental cost effectiveness (i.e., additional emission reduction). The cost effectiveness associated with moving from Regulatory Alternative III to IV was judged to be unreasonably high for NSPS. In addition, the economic impact analysis indicated a potential for adverse economic effects on some small plants under Alternatives IV and V.

The NSPS are nationwide standards applicable to the broad spectrum of conditions that can be found at sulfur recovery facilities in locations across the country. The NSPS do not constrain State and local regulatory officials from establishing more stringent requirements based on the specific natural gas processing plant or environmental conditions that may be found in a particular region. Indeed, many facilities will be subject to the requirements of "best available control technology" (BACT) or "lowest achievable emission rate" (LAER) under Parts C and D of the Act. BACT and LAER must be as stringent as, and may be more stringent than, the NSPS. The Administrator is aware of existing facilities meeting more stringent requirements and expects similar situations to arise in the future. Even so, these situations are dependent on regional or site-specific factors that cannot be accounted for in national standards. For these reasons, the Agency continues to believe that Regulatory Alternative III is the most appropriate basis for the NSPS.

Comment: The commenter (IV-D-8) stated that meaningful national emissions standards cannot be structured to account for the wide nationwide variations in plant treating volumes and acid gas ratios, both of which affect the selection of appropriate control technology. The commenter believes that individual State programs are more capable of handling these variations on a case-by-case basis, especially for small plants.

Response: The EPA agrees that individual State programs are more capable of handling case-specific regulatory concerns than are the NSPS. It is not the intention of EPA to preempt these State regulatory functions. Rather, it is to provide national standards to provide a minimum uniform level of control.

The EPA disagrees with the commenter's contention that meaningful standards cannot be structured to account for the wide variations in sour natural gas plant characteristics. The proposed standards are based on an analysis of the entire range of sulfur feed rates and the percent H_2S in the acid gas expected to be found in domestic sour gas processing facilities. Moreover, the efficiency equations within the standards were evaluated to determine their effect over the same ranges of expected facility characteristics. In no instance were the standards found to be unattainable or result in any unreasonable cost or economic impacts. Consequently, EPA is retaining the level and format of the proposed standards.

Comment: Two commenters (IV-D-7 and IV-D-15) stated that the proposed NSPS with its 1 LT/D plant size cutoff would encourage the building of smaller, less efficient or uncontrolled plants in lieu of larger, centralized plants to avoid control requirements. One commenter (IV-D-7) cited examples of small plant proliferation in the State of Michigan in response to a PSD cutoff as the basis for his concern. The commenter believes that the 1 LT/D cutoff in the proposed standard may lead to the same problem.

Response: The decision for the proposed plant size cutoff of 1 LT/D was based on cost effectiveness. (Since proposal, a revised analysis, incorporating updated assumptions, established the cutoff at 2 LT/D, using the same cost-effectiveness criterion.)

The Agency shares the commenter's concern that small plant (<2 LT/D) proliferation may occur as a means of circumventing the standards. This is a possibility with almost all cutoffs. However, the cutoff cannot be raised since it would result in a cost-effectiveness value judged by the Administrator to be unreasonable for plants covered by this NSPS. To encourage the construction of larger, more efficient plants, State agencies, with the authority to require more stringent control than required by the NSPS and to consider case-by-case situations, may require plants with sulfur feed rates <2 LT/D to reduce SO_2 emissions.

Comment: Commenter IV-D-15 recommended that the sulfur recovery efficiencies required for large plants be reduced. The commenter pointed out that the proposed standards, which require higher sulfur recovery efficiencies for large plants than for small plants, limit the economic incentive to construct large plants. The State of Michigan Department of Natural Resources, which regulates the commenter's plants, has encouraged natural gas producers to form centralized cooperatives and the commenter believes that the proposed Federal regulation may cause the number of small facilities to increase and, therefore, cause increased environmental impacts. He recommended that a low recovery efficiency be required regardless of plant size to eliminate the inequity and maintain the incentive to construct large plants. The commenter claimed that such an action would not cause a net increase in SO_2 emissions, but would eliminate the deleterious effects of multiple small plants being built in close proximity to one another.

Response: The purpose of NSPS is not to encourage or discourage the construction of certain sized plants. The standards are intended to be economically neutral by assuring that no adverse economic impacts would result. The standards in this case may have the effect of eliminating or limiting the economic incentive which may currently exist in Michigan to construct larger, centralized facilities. However, the economies of scale offered by larger plants may still provide an incentive to build larger facilities.

The Agency's major objection to the commenter's suggestion is that a uniformly low reduction efficiency would not reflect BDT for larger units and would, therefore, be inconsistent with Section 111 of the Clean Air Act. The Act requires the Agency to base the standards on BDT for each category of sources regulated. If a low recovery efficiency is promulgated which larger plants could easily achieve, the standards would not reflect BDT for these larger units since they are capable of achieving higher efficiencies at a reasonable cost.

2.15 MISCELLANEOUS COMMENTS

Comment: The commenter (IV-F-2) affirmed that the sulfur recovery levels set by Regulatory Alternative III are a practical basis for regulating the gas industry. In addition, Alternatives IV, V, and VI are believed by the commenter to be too stringent.

Response: No response is necessary.

Comment: In response to an EPA inquiry in the proposal preamble concerning 250 to 1,000 LT/D plants with H_2S concentrations less than 50 mole percent, the commenter (IV-D-13) reported that his company (Exxon) had one such plant in operation and projected installation of two others. The commenter claimed that sulfur recovery facilities for these plants would be generally consistent with those in the proposed standards, but the testing, monitoring, and reporting requirements and costs would not be required in the absence of the NSPS.

Response: No response is necessary.

Comment: The commenter (IV-D-21) stated his support of comments presented in Docket Entries IV-F-5 and IV-D-29 and wished to express concurrence with those comments.

Response: No response is necessary.

Comment: The commenter (IV-D-18) questioned the statement in the preamble (49 FR 2658) that there "would be no significant impact on solid waste disposal," and claimed that the statement could not be verified at this time. The commenter stated that there likely will be significant cost, permitting, transportation, and other impacts associated with sulfur disposal at small facilities.

Response: The Agency's determination of "no significant impact on solid waste disposal" was based on results of disposal cost analysis and the classification under RCRA regulations of waste by-product sulfur as nonhazardous (II-B-41).

The $0.25/Mg/mile sulfur disposal cost considered for small plants in the cost analysis (BID, Chapter 8, Table 8-3) is believed to be reasonably representative of costs incurred by small plant operators. The $25/Mg sulfur disposal cost factor assumes an average 100 mile transport of sulfur prior to disposal and was based on information obtained from the Ralph M. Parsons Company.

Comment: The commenter (IV-D-18) recommended changing the designation of §60.646(c) and (d) to (b)(7) and (b)(8), respectively, with no change in wording.

Response: In response to this and other comments, §60.646 has been revised.

Comment: The commenter (IV-D-25) claimed that the reasoning used to justify the proposed standard was faulty and that the Agency confused the crude oil refining industry with the natural gas processing industry. The commenter stated differences in the two industries concerning location. For example, the commenter stated that a refinery is usually permanently located near transportation facilities such as waterways or pipelines to ensure a constant supply of crude oil. A gas processing plant, however, is usually skid mounted and located at or near the gas field and the life of the plant is determined by that of the gas field. Therefore, the commenter stated that refineries and chemical plants are usually located in highly industrialized areas with large populations and a typical gas plant is located at the gas field site in remote areas away from any type of large population base.

The commenter also stated that gas plants and any sulfur removal equipment is designed and sized based on life expectancy and size of the gas field. The commenter claimed that field life was usually 12 years. Refineries, however, are sized and designed based on marketing requirements for the various products at the refinery and the type of crude to be refined. The commenter stated that most refineries have long term crude oil supply contracts and that feed to the facility is constant.

Response: The Agency recognizes the differences in the crude oil refining industry and the natural gas processing industry. Each of the characteristics of natural gas sulfur recovery plants identified by the commenter has been taken into account, to the extent possible, in the analyses and rationale supporting the standards. The reasoning used to justify the standards is not regarded as faulty. The fact that the source is located away from population centers is not relevant because SO_2 is a long-range pollutant.

In its evaluation of comments received on the proposed standards, the Agency carefully assessed the concerns of remote facilities. In response to those concerns, the standards have been revised to require sulfur measurements on a 24-hour, rather than a 12-hour, basis. Also, for smaller plants, a 12-year field life was used in the revised economic impact analysis.

Comment: The commenter (IV-D-29) questioned paragraph 60.646(b)(3) of the standard, which he reported required a continuous SO_2 monitor if the emission reduction efficiency standards in paragraphs 60.642(a) or (b) are to be achieved using an oxidation control system (thermal incinerator) or a reduction control system (SCOT tail gas unit) followed by an incinerator. The commenter stated that thermal incinerators will not achieve sulfur reduction but convert H_2S to SO_2.

Response: The section in question was not meant to imply that incineration is a sulfur recovery process. The purpose of the incinerator is the oxidation of H_2S to SO_2; the SCOT unit provides tail gas cleanup.

Comment: The commenter (IV-D-30) recommended that the Agency give serious thought to withdrawing the proposed NSPS because in the commenter's opinion, the rule does not meet the legislative criteria of Sections 111(f)(2)(A) through (C) of the Act.

Response: The proposed rule meets the criteria set forth in the Act. The Administrator is required to consider: (a) the quantity of air pollutant emissions that each category will emit or will be designed to emit; (b) the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare; and (c) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new source standards of performance [Sections 111(f)(2)(A) through (C)].

Onshore natural gas processing has been determined to be a major source of SO_2 emissions. The natural gas processing industry emits an estimated 250,000 megagrams per year of sulfur dioxide (Volume I BID, pg. 3-9). A typical 5 LT/D plant emits about 3,500 Mg of SO_2 per year.

The Administrator has determined that emissions from this source contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. This is reflected in the EPA priority list (40 CFR 60.16 amended at 47 FR 951, January 8, 1982) in which the natural gas producing industry ranks 29th out of 59 source categories. (See Section 2.1, pg. 2-1, of this document for a detailed discussion of this topic.)

Comment: The commenter (IV-D-31) claimed that older plants do not have the incentive to decrease emissions when repairs exceed 50 percent because it would trigger NSPS. This all-or-nothing philosophy often results in nothing.

Response: No reconstructions were projected in this proposed standard because of its application to sweetening units and sweetening units followed by sulfur recovery units.

"Reconstructions" were not projected because no situations in the industry are anticipated in which the replacement costs would exceed 50 percent of the cost of an entirely new facility.

Comment: The commenter (IV-D-31) stated that specific mention of a licensed process (e.g., Selectox, SCOT, Sulfreen, etc.) is not desirable because it makes new processes harder to get approved. Instead, Table 6-1 in the background information document should give percentage recovery required and then list the acceptable percentage recovery for all currently proven processes.

Response: In developing the basis for the standard, the Agency surveyed all available demonstrated and emerging technologies applicable to SO_2 emissions from natural gas processing. Following the survey, certain of these technologies were ultimately selected as representative of BDT. The BDT classification does not imply that a specified process must be applied. The plant operator may select any control technology which meets the emission reduction efficiency required by the standard.

Appendix A: Revised Economic Impact Analysis

A.1. Introduction

The NSPS will raise production costs for natural gas wells producing sour gas. The economic impact on these wells will differ depending on the size of the well, the gas flow, the percent of H_2S in sour gas, and the percent of the acid gas containing H_2S. Other parameters such as the price of natural gas and the price of recovered elemental sulfur also affect the economic well being of natural gas wells but in a fairly consistent manner across well sizes and gas characteristics. The objective of this revised economic analysis was to identify by size and gas characteristics any sour natural gas wells to be built or reconstructed in the future, that will incur an adverse economic impact due to the NSPS.

As the results of this analysis show, for new plants likely to be built in the future, the NSPS does not impose adverse economic impacts and therefore will not force the cancellation or postponement of construction of any planned onshore gas processing facilities. Consequently, reductions in output levels are expected to be very slight and are not expected to encourage significantly higher gas prices, or any other disruption of the natural gas industry.

Appendix A is organized as follows. The general methodology used to conduct the economic analysis is discussed in the next section of the appendix, followed by a description of the data requirements in Section A.3. Miscellaneous program variables necessary to run the discounted cash flow model are explained in Section A.4. The discounted cash flow analysis is discussed in Section A.5 with results described and examples presented in Section A.6.

A.2. Methodology

The revised economic analysis has been conducted because several key data inputs have changed since the original analysis was completed and because it was learned during the comment period that sweetening costs were erroneously omitted from the original analysis. The major data revisions are as follows:

1. In the original analysis the price of natural gas was assumed to be $4.80/MCF in 1987 (in 1980 dollars). This price assumed deregulation in 1985. In the revised analysis deregulation is

also assumed to occur but a different price forecast and year dollars (1984) have been used. The price of natural gas is assumed to increase at a constant rate until 1994 as follows:

	(1984$/MCF)
1985	$3.88
1986	4.06
1987	4.25
1988	4.44
1989	4.64
1990	4.86
1991	5.08
1992	5.32
1993	5.56
1994	5.82

2. In the original analysis a price of $100/ton was assumed for recovered sulfur. The price has been lowered to $77/ton based on comments received. No sulfur recovery credits are assumed for plants less than 5 LT/D sulfur intake.
3. In the original study a real cost of capital of 2% was used. In the revised analysis a real cost of capital of 6% is used based on a prime rate of 11% and an inflation rate of 5%.
4. Capacity utilization for the purposes of generating revenues from sweet gas sales and sulfur sales is assumed to be 75%.
5. The original analysis assumed a well life and equipment life of 20 years for all size plants. In the revised analysis the well life for plants less than or equal to 20 LT/D is assumed to be 12 years. Equipment life is assumed to be 20 years and a salvage value is therefore included. The salvage value is calculated based on straight line depreciation (i.e., after the 12th year, 40% of equipment value is assumed to remain). The salvage value is treated as a cash inflow at the end of the 12th year. For plants greater than 20 LT/D, the well life and equipment life are both assumed to be 20 years.
6. No severance tax was assumed in the original study. In this revised report, severance tax has been considered by the discounted

cash flow model as a five percent reduction in revenue. The five percent represents an average across all natural gas producing states.[1]

As stated earlier, the objective of this revised analysis is to identify by size and gas characteristics those future plants that will be adversely affected by the NSPS. This is achieved by conducting a net present value (NPV) analysis under both the baseline and Regulatory Alternative III. For a review of the controls to be imposed under Regulatory Alternative III see BID Table 6-1. The NPV analysis calculates the present value of all cash flows associated with a project. If the resulting value is positive, the project is economically feasible because cash inflows exceed cash outlays. If the net present value is negative the project is not economically feasible.

A.3. Data Requirements

The first step in the revised analysis was to identify the range of potential new plants by size and gas characteristics. Joint probability distributions considering size of plant, H_2S in the wellhead gas and H_2S in the acid gas were created based on historical data. The result was the identification of all plants by size, H_2S in wellhead gas and H_2S in acid gas that have a positive probability of being built in the future. Tables A.1 through A.3 form the basis for these probability tables. Table A.1 shows the various probabilities of plants within different size ranges having H_2S in the acid gas within the specified ranges. Table A.2 shows the various probabilities of plants within different size ranges having H_2S in the sour gas within the specified ranges. Table A.3 shows the probabilities of sour gas treating facilities being within the specified size ranges. The combination of these three tables forms the basis for Tables A.4 through A.10. These tables represent the probabilities of future plants being within the different size ranges and having the various gas characteristics stated.

This is the realm of plants that are of interest to us in determining economic impacts of the NSPS. Plants that are not likely to be built will obviously not be affected by the NSPS.

Cost Analysis

Sulfur credits are calculated and shown in Table A.11 for the baseline scenario. Sulfur credits are in 1984 dollars and are calculated based on an average freight on board recovered sulfur price of $77/ton. See Docket entry IV-B-3. Sulfur credits are calculated assuming a capacity utilization of 75%. In the baseline it is assumed that there are no controls for those plants 7 LT/D and less. See BID Table 6-1 for baseline control strategies for plants greater than 7 LT/D. Production costs are included in the capital and annual costs. Working capital (i.e., inventories, cash, accounts receivables, etc.) is calculated at 20% of capital costs based on a survey of oil and gas producing companies made by Chase Manhattan between 1977 and 1981.[2] Table A.12 shows the same types of costs for Regulatory Alternative III, (i.e., the NSPS).

Revenues

The volume of sweet gas for sale from each plant likely to be built in the future was calculated based on the size of the plant and the gas characteristics. As can be seen in Table A.13., this calculation excludes the amount of sweet gas that is consumed in the sweetening plant operation. The volumes reflected in Table A.13 are based on 100% capacity utilization. These volumes have therefore been reduced by 25% to reflect the current assumption of 75% capacity utilization. Revenues from sweet gas sales were calculated for each year 1985-1999 by multiplying the volume of sweet gas (at 75% capacity utilization) for sale by the appropriate price of wellhead natural gas. See the natural gas prices, 1985-1994, on page A.2. As noted earlier, revenues from sweet gas sales were further reduced an additional five percent to reflect severance taxes. The projected average natural gas prices were generated from the hydrocarbon supply model developed by Energy and Environmental Analysis, Inc. and referenced in their July 1984 report entitled "Regional Forecasts of Industrial Residual Fuel Oil and Natural Gas Prices" (Docket entry IV-A-4). These prices represent the marginal price for new gas only and assume deregulation of natural gas in 1985.

A.4. Other Program Variables

In order to use a discounted cash flow model to perform the net present value analysis, several other program variables needed to be specified. The ratio of debt to total assets has not been revised from the original analysis. A 50% debt to total assets ratio is used based on Table 9-14 of the original economic impact analysis. See page 9-32 of the proposal BID. The nominal rate of interest of 11% was selected based on the current prime rate. The nominal rate of return on equity for this industry is estimated to be 12.5%.

TABLE A.1.

FACILITY SIZE (MG/D SULFUR)	PROBABILITY OF A FACILITY WITHIN A GIVEN SIZE RANGE HAVING A %H2S IN THE ACID GAS WITHIN THE SPECIFIED RANGES										
	%H2S IN THE ACID GAS										
	<0.00001	>0.00001 <0.0001	>0.0001 <0.001	>0.001 <0.01	>0.01 <0.02	>0.02 <0.05	>0.05 <0.125	>0.125 <0.20	>0.20 <0.5	>0.5 <0.8	>0.8 <1.0
<0.0002											
0.00021-0.0003											
0.00031-0.0004											
0.00041-0.0005											
0.00051-0.0006	NONE	0.1700	0.8300								
0.00061-0.0007		0.2400	0.7600								
0.00071-0.0008		0.3100	0.6900								
0.00081-0.0009		0.2400	0.5200	0.2500							
0.00091-0.0010		0.1900	0.6200	0.2000							
0.0011-0.002		0.1900	0.4300	0.3800							
0.0021-0.003		0.1700	0.3400	0.4900							
0.0031-0.004		0.2100	0.2700	0.5200							
0.0041-0.005		0.1200	0.5100	0.3700							
0.0051-0.006		0.1000	0.4600	0.4400							
0.0061-0.007		0.1500	0.3200	0.5300							
0.0071-0.008		0.0900	0.6100	0.2900							
0.0081-0.009		0.0700	0.6600	0.2800							
0.0091-0.010		0.0800	0.4300	0.4900							
0.011-0.02		0.0500	0.4300	0.2400	0.1700	0.1000	0.0100				
0.021-0.03		0.0400	0.3900	0.2600	0.1800	0.1000	0.0100				
0.031-0.04		0.0400	0.2600	0.3100	0.2200	0.1200	0.0200	0.0100	0.0060	0.0020	0.0003
0.041-0.05		0.1000	0.2100	0.4100	0.1800	0.0600	0.0200	0.0190	0.0150	0.0070	0.0005
0.051-0.06		0.0500	0.1100	0.4400	0.1200	0.1000	0.0800	0.0600	0.0260	0.0010	0.0005
0.061-0.07		0.0060	0.1300	0.5100	0.1500	0.0850	0.0490	0.0380	0.0180	0.0070	0.0020
0.071-0.08		0.0080	0.3300	0.3200	0.1400	0.0800	0.0500	0.0400	0.0200	0.0100	0.0050
0.081-0.09		0.0140	0.3050	0.2910	0.1660	0.0970	0.0550	0.0430	0.0190	0.0070	0.0010
0.091-0.10		0.0420	0.4590	0.2190	0.1250	0.0680	0.0040	0.0290	0.0140	0.0060	0.0020
0.11-1.0		0.0090	0.1860	0.1770	0.1770	0.1500	0.1260	0.1000	0.0470	0.0210	0.0080
1.1-2.0		0.0004	0.0320	0.0730	0.0900	0.4040	0.1640	0.0580	0.1250	0.0440	0.0100
2.1-3.0		0.0004	0.0090	0.2120	0.0760	0.0480	0.2080	0.1260	0.2040	0.0870	0.0300
3.1-4.0				0.1150	0.0330	0.0130	0.1230	0.5450	0.0980	0.0630	0.0110
4.1-5.0				0.1750	0.0500	0.0190	0.1560	0.0830	0.3370	0.1430	0.0370
5.1-10.0				0.0880	0.0650	0.0180	0.1170	0.1250	0.3780	0.1970	0.0510
10.1-20.0				0.0090	0.0100	0.0110	0.0500	0.1990	0.4300	0.2440	0.0490
20.1-30.0						0.0780	0.1100	0.1560	0.4210	0.1790	0.0560
30.1-40.0								0.1580	0.5120	0.2540	0.0760
40.1-50.0								0.1100	0.5920	0.2100	0.0880
50.1-60.0								0.0580	0.5730	0.3050	0.0640
60.1-70.0								0.0490	0.6170	0.1970	0.1370
70.1-80.0								0.0050	0.3160	0.5390	0.1410
80.1-90.0								0.0010	0.5370	0.3430	0.1190
90.1-100.0									0.4700	0.4000	0.1300
100.1-110.0									0.4700	0.4000	0.1300
110.1-120.0									0.4700	0.4000	0.1300
120.1-130.0									0.3000	0.4300	0.2700
130.1-140.0									0.3900	0.4700	0.1400
140.1-150.0									0.3000	0.3200	0.3800
150.1-160.0									0.2100	0.4900	0.3000
160.1-170.0									0.2300	0.4800	0.2900
170.1-180.0									0.1400	0.5300	0.3300
180.1-190.0									0.0700	0.5800	0.3500
190.1-200.0									0.0700	0.4300	0.5000
200.1-300.0										0.1200	0.8800
300.1-500.0											1.0000
500.1-750.0											1.0000
750.1-1000.0											1.0000
>1000.1											1.0000

TABLE A.2.

PROBABILITY OF A FACILITY WITHIN A GIVEN SIZE RANGE HAVING A %H2S IN THE SOUR GAS WITHIN THE SPECIFIED RANGES

FACILITY SIZE (MG/D SULFUR)	%H2S IN THE SOUR GAS <0.000004	>0.000004 <0.00001	>0.00001 <0.0001	>0.0001 <0.001	>0.001 <0.01	>0.01 <0.02	>0.02 <0.05	>0.05 <0.125	>0.125 <0.20	>0.20 <0.5
<0.0002										
0.00021-0.0003										
0.00031-0.0004	1.0000									
0.00041-0.0005	1.0000									
0.00051-0.0006	1.0000									
0.00061-0.0007	1.0000									
0.00071-0.0008	1.0000									
0.00081-0.0009	0.8500	0.1500								
0.00091-0.0010	0.9400	0.0600								
0.0011-0.002	0.8100	0.1900								
0.0021-0.003	0.4500	0.3200	0.2300							
0.0031-0.004	0.2400	0.4400	0.3200							
0.0041-0.005	0.3400	0.3500	0.2600	0.0400	0.0100					
0.0051-0.006	0.4100	0.2600	0.1900	0.0900	0.0500					
0.0061-0.007	0.2800	0.2500	0.3900	0.0600	0.0100					
0.0071-0.008	0.3900	0.3500	0.1200	0.0800	0.0500					
0.0081-0.009	0.3000	0.1800	0.3700	0.1200	0.0400					
0.0091-0.010	0.3100	0.2800	0.2200	0.1200	0.0600					
0.011-0.02	0.3200	0.2500	0.2900	0.1000	0.0300					
0.021-0.03	0.2000	0.1800	0.4400	0.1400	0.0500					
0.031-0.04	0.1800	0.2500	0.3400	0.1600	0.0700					
0.041-0.05	0.0900	0.2100	0.4800	0.1600	0.0600					
0.051-0.06	0.1600	0.2200	0.3000	0.1900	0.1300					
0.061-0.07	0.1300	0.2200	0.3600	0.1900	0.1000					
0.071-0.08	0.1100	0.2000	0.3800	0.2000	0.1100					
0.081-0.09	0.0700	0.1300	0.2700	0.4400	0.0900					
0.091-0.10	0.0700	0.1400	0.2600	0.4300	0.1000					
0.11-1.0			0.2000	0.4800	0.3200					
1.1-2.0				0.4100	0.4900	0.0700	0.0400			
2.1-3.0				0.3700	0.5200	0.1100	0.0700			
3.1-4.0				0.2100	0.6100	0.1300	0.0500			
4.1-5.0				0.1800	0.6100	0.1300	0.0800			
5.1-10.0				0.1700	0.5600	0.1800	0.0700	0.0200		
10.1-20.0				0.0700	0.4400	0.2200	0.2200	0.0400		
20.1-30.0					0.3700	0.2800	0.2600	0.0800	0.0200	
30.1-40.0					0.3300	0.2900	0.2600	0.1000	0.0200	
40.1-50.0					0.2500	0.2700	0.3200	0.1400	0.0200	
50.1-60.0					0.2000	0.3000	0.2800	0.1900	0.0400	
60.1-70.0					0.1000	0.3700	0.2800	0.2000	0.0400	
70.1-80.0						0.2400	0.3300	0.3800	0.0400	
80.1-90.0							0.4700	0.4400	0.0900	
90.1-100.0							0.2400	0.2800	0.4800	
100.1-110.0							0.4700	0.4800	0.0400	
110.1-120.0							0.3500	0.4600	0.1900	
120.1-130.0							0.3200	0.5500	0.1200	
130.1-140.0							0.3600	0.5200	0.1200	
140.1-150.0							0.2300	0.6300	0.1400	
150.1-160.0							0.1100	0.6700	0.2200	
160.1-170.0								0.7500	0.2500	
170.1-180.0								0.6000	0.4000	
180.1-190.0								0.7500	0.2500	
190.1-200.0								0.6000	0.4000	
200.1-300.0								0.9100	0.0900	
300.1-500.0									1.0000	
500.1-750.0									0.5000	0.5000
750.1-1000.0										1.0000
>1000.1										1.0000

TABLE A.3. PROBABILITY OF A NEW SOUR GAS SWEETENING FACILITY BEING IN A SPECIFIED SIZE RANGE

FACILITY SIZE (MG/D SULFUR)	NUMBER OF FACILITIES	CUMULATIVE NUMBER OF FACILITIES	CUMULATIVE PROBABILITY	SMOOTHED CUMULATIVE PROBABILITY	SMOOTHED DISCRETE PROBABILITY	SMOOTHED NUMBER OF DISCRETE FACILITIES
<0.0002						
0.00021-0.0003	1.0000	1.0000	0.0037	0.0037	0.0037	1.0000
0.00031-0.0004		1.0000	0.0037	0.0070	0.0032	0.8557
0.00041-0.0005	2.0000	3.0000	0.0112	0.0112	0.0043	1.1444
0.00051-0.0006	1.0000	4.0000	0.0150	0.0150	0.0037	1.0000
0.00061-0.0007	2.0000	6.0000	0.0225	0.0225	0.0075	2.0000
0.00071-0.0008	3.0000	9.0000	0.0337	0.0337	0.0112	3.0000
0.00081-0.0009	1.0000	10.0000	0.0375	0.0375	0.0037	1.0000
0.00091-0.0010	4.0000	14.0000	0.0524	0.0524	0.0150	4.0000
0.0011-0.002	9.0000	23.0000	0.0861	0.0861	0.0337	9.0000
0.0021-0.003	3.0000	26.0000	0.0974	0.0974	0.0112	3.0000
0.0031-0.004	3.0000	29.0000	0.1086	0.1086	0.0112	3.0000
0.0041-0.005	5.0000	34.0000	0.1273	0.1273	0.0187	5.0000
0.0051-0.006	6.0000	40.0000	0.1498	0.1498	0.0225	6.0000
0.0061-0.007	1.0000	41.0000	0.1536	0.1536	0.0037	1.0000
0.0071-0.008	2.0000	43.0000	0.1610	0.1610	0.0075	2.0000
0.0081-0.009	2.0000	45.0000	0.1685	0.1685	0.0075	2.0000
0.0091-0.010	9.0000	54.0000	0.2022	0.2022	0.0337	9.0000
0.011-0.02	13.0000	67.0000	0.2509	0.2509	0.0487	13.0000
0.021-0.03	8.0000	75.0000	0.2809	0.2809	0.0300	8.0000
0.031-0.04	5.0000	80.0000	0.2996	0.2996	0.0187	5.0000
0.041-0.05	2.0000	82.0000	0.3071	0.3071	0.0075	2.0000
0.051-0.06		82.0000	0.3071	0.3109	0.0037	1.0000
0.061-0.07	2.0000	84.0000	0.3146	0.3146	0.0037	1.0000
0.071-0.08	3.0000	87.0000	0.3258	0.3258	0.0112	3.0000
0.081-0.09		87.0000	0.3258	0.3446	0.0187	5.0000
0.091-0.10	10.0000	97.0000	0.3633	0.3633	0.0187	5.0000
0.11-1.0	50.0000	147.0000	0.5506	0.5506	0.1873	50.0000
1.1-2.0	12.0000	159.0000	0.5955	0.5955	0.0449	12.0000
2.1-3.0	7.0000	166.0000	0.6217	0.6217	0.0262	7.0000
3.1-4.0	8.0000	174.0000	0.6517	0.6517	0.0300	8.0000
4.1-5.0	7.0000	181.0000	0.6779	0.6779	0.0262	7.0000
5.1-10.0	12.0000	193.0000	0.7228	0.7228	0.0449	12.0000
10.1-20.0	10.0000	203.0000	0.7603	0.7603	0.0375	10.0000
20.1-30.0	21.0000	224.0000	0.8390	0.8390	0.0787	21.0000
30.1-40.0	14.0000	238.0000	0.8914	0.8914	0.0524	14.0000
40.1-50.0	6.0000	244.0000	0.9139	0.9139	0.0225	6.0000
50.1-60.0	1.0000	245.0000	0.9176	0.9176	0.0037	1.0000
60.1-70.0	5.0000	250.0000	0.9363	0.9363	0.0187	5.0000
70.1-80.0	3.0000	253.0000	0.9476	0.9476	0.0112	3.0000
80.1-90.0	1.0000	254.0000	0.9513	0.9513	0.0037	1.0000
90.1-100.0		254.0000	0.9513	0.9532	0.0019	0.5000
100.1-110.0	1.0000	255.0000	0.9551	0.9551	0.0019	0.5000
110.1-120.0		255.0000	0.9551	0.9563	0.0012	0.3333
120.1-130.0		255.0000	0.9551	0.9576	0.0012	0.3333
130.1-140.0	1.0000	256.0000	0.9588	0.9588	0.0012	0.3333
140.1-150.0		256.0000	0.9589	0.9607	0.0019	0.5000
150.1-160.0	1.0000	257.0000	0.9625	0.9625	0.0019	0.5000
160.1-170.0		257.0000	0.9625	0.9638	0.0012	0.3333
170.1-180.0		257.0000	0.9625	0.9650	0.0012	0.3333
180.1-190.0	1.0000	258.0000	0.9663	0.9663	0.0012	0.3333
190.1-200.0	2.0000	260.0000	0.9738	0.9738	0.0075	2.0000
200.1-300.0	2.0000	262.0000	0.9813	0.9813	0.0075	2.0000
300.1-500.0	2.0000	264.0000	0.9888	0.9888	0.0075	2.0000
500.1-750.0		264.0000	0.9888	0.9925	0.0037	1.0000
750.0-1000.0	2.0000	266.0000	0.9963	0.9963	0.0037	1.0000
>1000	1.0000	267.0000	1.0000	1.0000	0.0037	1.0000
	267.0000					267.0000

TABLE A.4.

PROBABILITY OF A FACILITY WITHIN A GIVEN SIZE RANGE HAVING A %H2S IN THE ACID GAS WITHIN THE SPECIFIED RANGES AND A %H2S IN THE SOUR GAS OF 0.01 TO 0.1 PERCENT

FACILITY SIZE (MG/D SULFUR)	%H2S IN THE ACID GAS										
	<0.00001	>0.00001 <0.0001	>0.0001 <0.001	>0.001 <0.01	>0.01 <0.02	>0.02 <0.05	>0.05 <0.125	>0.125 <0.20	>0.20 <0.5	>0.5 <0.8	>0.8 <1.0
0.11-1.0	0.0000	0.0043	0.0893	0.0850	0.0850	0.0720	0.0605	0.0480	0.0226	0.0101	0.0035
1.1-2.0	0.0000	0.0002	0.0131	0.0299	0.0369	0.1656	0.0672	0.0238	0.0513	0.0180	0.0041
2.1-3.0	0.0000	0.0001	0.0033	0.0784	0.0281	0.0178	0.0770	0.0466	0.0755	0.0322	0.0111
3.1-4.0	0.0000	0.0000	0.0000	0.0242	0.0069	0.0027	0.0258	0.1145	0.0206	0.0132	0.0023
4.1-5.0	0.0000	0.0000	0.0000	0.0315	0.0090	0.0034	0.0281	0.0149	0.0607	0.0257	0.0067
5.1-10.0	0.0000	0.0000	0.0000	0.0150	0.0111	0.0031	0.0199	0.0213	0.0643	0.0335	0.0087
10.1-20.0	0.0000	0.0000	0.0000	0.0006	0.0007	0.0008	0.0035	0.0139	0.0301	0.0171	0.0034
20.1-30.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
30.1-40.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
40.1-50.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
50.1-60.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
60.1-70.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
70.1-80.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
80.1-90.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
90.1-100.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
100.1-110.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
110.1-120.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
120.1-130.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
130.1-140.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
140.1-150.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
150.1-160.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
160.1-170.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
170.1-180.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
180.1-190.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
190.1-200.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
200.1-300.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
300.1-500.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
500.1-750.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
750.1-1000.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
>1000.1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

TABLE A.5.

FACILITY SIZE (MG/D SULFUR)	PROBABILITY OF A FACILITY WITHIN A GIVEN SIZE RANGE HAVING A %H2S IN THE ACID GAS WITHIN THE SPECIFIED RANGES AND A %H2S IN THE SOUR GAS OF 0.1 TO 1.0 PERCENT _____ %H2S IN THE ACID GAS									
	<0.00001	>0.00001 <0.0001	>0.0001 <0.001	>0.001 <0.01	>0.01 <0.02	>0.02 <0.05	>0.05 <0.125	>0.125 <0.20	>0.20 <0.5	>0.5 <0.8	>0.8 <1.0
0.11-1.0	0.0000	0.0029	0.0595	0.0566	0.0566	0.0480	0.0403	0.0320	0.0150	0.0067	0.0026
1.1-2.0	0.0000	0.0002	0.0157	0.0358	0.0441	0.1980	0.0804	0.0294	0.0613	0.0216	0.0049
2.1-3.0	0.0000	0.0002	0.0047	0.1102	0.0395	0.0250	0.1082	0.0655	0.1061	0.0452	0.0156
3.1-4.0	0.0000	0.0000	0.0000	0.0702	0.0201	0.0079	0.0750	0.3325	0.0598	0.0384	0.0067
4.1-5.0	0.0000	0.0000	0.0000	0.1068	0.0305	0.0116	0.0952	0.0506	0.2056	0.0872	0.0226
5.1-10.0	0.0000	0.0000	0.0000	0.0493	0.0364	0.0101	0.0655	0.0700	0.2117	0.1103	0.0286
10.1-20.0	0.0000	0.0000	0.0000	0.0040	0.0044	0.0048	0.0220	0.0876	0.1892	0.1074	0.0211
20.1-30.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0289	0.0407	0.0577	0.1558	0.0662	0.0207
30.1-40.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0521	0.1690	0.0833	0.0251
40.1-50.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0275	0.1480	0.0525	0.0220
50.1-60.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0116	0.1146	0.0610	0.0128
60.1-70.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0049	0.0617	0.0197	0.0177
70.1-80.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
80.1-90.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
90.1-100.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
100.1-110.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
110.1-120.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
120.1-130.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
130.1-140.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
140.1-150.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
150.1-160.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
160.1-170.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
170.1-180.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
180.1-190.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
190.1-200.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
200.1-300.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
300.1-500.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
500.1-750.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
750.1-1000.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
>1000.1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

TABLE A.6.

PROBABILITY OF A FAC[illegible] WITHIN A GIVEN SIZE RANGE HAVING A %H2S IN THE ACID GAS WITHIN THE SPE[illegible]IFIED RANGES AND A %H2S IN THE SOUR GAS OF 1.0 TO 2.0 PERCENT_____%H2S IN THE ACID GAS

. FACILITY SIZE (MS/D SULFUR)	<0.00001	>0.00001 <0.0001	>0.0001 <0.001	>0.001 <0.01	>0.01 <0.02	>0.02 <0.05	>0.05 <0.125	>0.125 <0.20	>0.20 <0.5	>0.5 <0.8	>0.8 <1.0
0.11-1.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
1.1-2.0	0.0000	.0000	0.0022	0.0051	0.0063	0.0293	0.0115	0.0041	0.0039	0.0031	0.0007
2.1-3.0	0.0000	.0000	0.0010	0.0233	0.0084	0.0053	0.0229	0.0139	0.0224	0.0096	0.0033
3.1-4.0	0.0000	0.0000	0.0000	0.0150	0.0043	0.0017	0.0160	0.0709	0.0127	0.0082	0.0014
4.1-5.0	0.0000	0.0000	0.0000	0.0228	0.0065	0.0025	0.0203	0.0108	0.0438	0.0186	0.0045
5.1-10.0	0.0000	0.0000	0.0000	0.0158	0.0117	0.0032	0.0211	0.0225	0.0680	0.0355	0.0092
10.1-20.0	0.0000	0.0000	0.0000	0.0020	0.0022	0.0024	0.0110	0.0438	0.0946	0.0537	0.0106
20.1-30.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0218	0.0308	0.0437	0.1179	0.0501	0.0157
30.1-40.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0458	0.1485	0.0737	0.0220
40.1-50.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0297	0.1598	0.0567	0.0238
50.1-60.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0174	0.1719	0.0915	0.0192
60.1-70.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0181	0.2283	0.0729	0.0507
70.1-80.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0012	0.0758	0.1294	0.0738
80.1-90.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
90.1-100.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
100.1-110.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
110.1-120.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
120.1-130.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
130.1-140.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
140.1-150.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
150.1-160.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
160.1-170.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
170.1-180.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
180.1-190.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
190.1-200.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
200.1-300.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
300.1-500.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
500.1-750.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
750.1-1000.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
>1000.1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

TABLE A. 7.

FACILITY SIZE (MG/D SULFUR)	PROBABILITY OF A FACILITY WITHIN A GIVEN SIZE RANGE HAVING A %H2S IN THE ACID GAS WITHIN THE SPECIFIED RANGES AND A %H2S IN THE SOUR GAS OF 2.0 TO 5.0 PERCENT										
	%H2S IN THE ACID GAS										
	<0.00001	>0.00001 <0.0001	>0.0001 <0.001	>0.001 <0.01	>0.01 <0.02	>0.02 <0.05	>0.05 <0.125	>0.125 <0.20	>0.20 <0.50	>0.50 <0.80	>0.80 <1.00
0.11-1.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
1.1-2.0	0.0000	.0000	0.0013	0.0029	0.0036	0.0162	0.0066	0.0023	0.0050	0.0015	0.0004
2.1-3.0	0.0000	.0000	0.0006	0.0148	0.0053	0.0034	0.0146	0.0088	0.0143	0.0061	0.0021
3.1-4.0	0.0000	0.0000	0.0000	0.0058	0.0017	0.0007	0.0062	0.0273	0.0049	0.0032	0.0006
4.1-5.0	0.0000	0.0000	0.0000	0.0140	0.0040	0.0015	0.0125	0.0066	0.0270	0.0114	0.0030
5.1-10.0	0.0000	0.0000	0.0000	0.0062	0.0046	0.0013	0.0082	0.0088	0.0265	0.0138	0.0036
10.1-20.0	0.0000	0.0000	0.0000	0.0020	0.0022	0.0024	0.0110	0.0438	0.0946	0.0537	0.0106
20.1-30.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0203	0.0286	0.0406	0.1095	0.0465	0.0146
30.1-40.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0411	0.1331	0.0660	0.0198
40.1-50.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0352	0.1894	0.0672	0.0282
50.1-60.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0162	0.1604	0.0854	0.0179
60.1-70.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0137	0.1728	0.0552	0.0384
70.1-80.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017	0.1043	0.1779	0.0465
80.1-90.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.2524	0.1612	0.0559
90.1-100.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1128	0.0960	0.0312
100.1-110.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2209	0.1880	0.0611
110.1-120.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1645	0.1400	0.0455
120.1-130.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0960	0.1376	0.0864
130.1-140.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1404	0.1692	0.0504
140.1-150.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0690	0.0736	0.0874
150.1-160.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0231	0.0539	0.0330
160.1-170.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
170.1-180.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
180.1-190.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
190.1-200.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
200.1-300.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
300.1-500.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
500.1-750.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
750.1-1000.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
>1000.1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

TABLE A.8.

PROBABILITY OF A FACILITY WITHIN A GIVEN SIZE RANGE HAVING A %H2S IN THE ACID GAS WITHIN THE SPECIFIED RANGES AND A %H2S IN THE SOUR GAS OF 5.0 TO 12.5 PERCENT____%H2S IN THE ACID GAS

FACILITY SIZE (MG/D SULFUR)	<0.00001	>0.00001 <0.0001	>0.0001 <0.001	>0.001 <0.01	>0.01 <0.02	>0.02 <0.05	>0.05 <0.125	>0.125 <0.20	>0.20 <0.5	>0.5 <0.8	>0.8 <1.0
0.11-1.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
1.1-2.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2.1-3.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3.1-4.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.1-5.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5.1-10.0	0.0000	0.0000	0.0000	0.0019	0.0013	0.0004	0.0023	0.0025	0.0076	0.0039	0.0010
10.1-20.0	0.0000	0.0000	0.0000	0.0004	0.0004	0.0004	0.0020	0.0080	0.0172	0.0095	0.0019
20.1-30.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0062	0.0089	0.0125	0.0337	0.0143	0.0045
30.1-40.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0158	0.0512	0.0254	0.0076
40.1-50.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0154	0.0829	0.0294	0.0123
50.1-60.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0110	0.1089	0.0580	0.0122
60.1-70.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0098	0.1234	0.0394	0.0274
70.1-80.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0019	0.1201	0.2048	0.0536
80.1-90.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.2363	0.1509	0.0524
90.1-100.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1316	0.1120	0.0364
100.1-110.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2256	0.1920	0.0624
110.1-120.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2162	0.1840	0.0598
120.1-130.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1650	0.2365	0.1485
130.1-140.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2028	0.2444	0.0728
140.1-150.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1890	0.2016	0.2394
150.1-160.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1407	0.3283	0.2010
160.1-170.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1725	0.3600	0.2175
170.1-180.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0840	0.3180	0.1980
180.1-190.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0525	0.4350	0.2625
190.1-200.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0420	0.2580	0.3000
200.1-300.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1092	0.9000
300.1-500.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
500.1-750.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
750.1-1000.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
>1000.1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

TABLE A.9.

PROBABILITY OF A FACILITY WITHIN A GIVEN SIZE RANGE HAVING A %H2S IN THE ACID GAS WITHIN THE SPECIFIED RANGES AND A %H2S IN THE SOUR GAS OF 12.5 TO 20.0 PERCENT

FACILITY SIZE (MG/D SULFUR)	%H2S IN THE ACID GAS <0.00001	>0.00001 <0.0001	>0.0001 <0.001	>0.001 <0.01	>0.01 <0.02	>0.02 <0.05	>0.05 <0.125	>0.125 <0.20	>0.20 <0.5	>0.5 <0.8	>0.8 <1.0
0.11-1.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
1.1-2.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2.1-3.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3.1-4.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.1-5.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5.1-10.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
10.1-20.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
20.1-30.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0016	0.0022	0.0031	0.0084	0.0036	0.0011
30.1-40.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0032	0.0102	0.0051	0.0015
40.1-50.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0022	0.0118	0.0042	0.0018
50.1-60.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0023	0.0229	0.0122	0.0026
60.1-70.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020	0.0247	0.0079	0.0055
70.1-80.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0126	0.0216	0.0056
80.1-90.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0483	0.0309	0.0107
90.1-100.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2256	0.1920	0.0624
100.1-110.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0188	0.0160	0.0052
110.1-120.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0893	0.0760	0.0247
120.1-130.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0360	0.0516	0.0324
130.1-140.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0468	0.0564	0.0168
140.1-150.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0420	0.0448	0.0532
150.1-160.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0462	0.1078	0.0660
160.1-170.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0575	0.1200	0.0725
170.1-180.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0560	0.2120	0.1320
180.1-190.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0175	0.1450	0.0875
190.1-200.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0290	0.1720	0.2000
200.1-300.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0108	0.0792
300.1-500.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000
500.1-750.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.5000
750.1-1000.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
>1000.1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

TABLE A.10

FACILITY SIZE (MG/D SULFUR)	PROBABILITY OF A FACILITY WITHIN A GIVEN SIZE RANGE HAVING A %H2S IN THE ACID GAS WITHIN THE SPECIFIED RANGES AND A %H2S IN THE SOUR GAS OF 20.0 TO 50.0 PERCENT ___ %H2S IN THE ACID GAS										
	<0.00001	>0.00001 <0.0001	>0.0001 <0.001	>0.001 <0.01	>0.01 <0.02	>0.02 <0.05	>0.05 <0.125	>0.125 <0.20	>0.20 <0.5	>0.5 <0.8	>0.8 <1.0
0.11-1.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
1.1-2.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2.1-3.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3.1-4.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.1-5.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5.1-10.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
10.1-20.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
20.1-30.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
30.1-40.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
40.1-50.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
50.1-60.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
60.1-70.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
70.1-80.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
80.1-90.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
90.1-100.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
100.1-110.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
110.1-120.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
120.1-130.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
130.1-140.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
140.1-150.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
150.1-160.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
160.1-170.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
170.1-180.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
180.1-190.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
190.1-200.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
200.1-300.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
300.1-500.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
500.1-750.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.5000
750.1-1000.0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000
>1000.1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000

TABLE A.11. BASELINE COSTS
($1000-1984)

FACILITY SIZE (LT/D)	ACID GAS %H_2S	SOUR GAS %H_2S	CAPITAL COST 1/	ANNUAL O&M 2/	SULFUR CREDIT 3/	NET ANNUAL O&M	WORKING CAPITAL 4/	SALVAGE VALUE 5/
2	2	1	2827	288		288	565	1131
2	5	3	1986	207		207	397	794
2	5	2	1986	207		207	397	794
2	5	1	2015	216		216	403	806
2	12.5	5	1652	170		170	330	661
2	12.5	4	1661	178		178	332	664
2	12.5	3	1661	178		178	332	664
2	12.5	2	1661	178		178	332	664
2	12.5	1	1690	187		187	338	676
2	20	5	1580	171		171	316	632
2	20	4	1580	171		171	316	632
2	20	3	1580	171		171	316	632
2	20	2	1580	171		171	316	632
2	20	1	1609	180		180	322	644
2	50	5	1499	164		164	300	600
2	50	4	1499	164		164	300	600
2	80	5	1479	162		162	296	592
3	2	1	3504	349		349	701	1402
3	5	3	2257	231		231	451	903
3	5	2	2257	231		231	451	903
3	12.5	5	1770	188		188	354	708
3	12.5	4	1770	188		188	354	708
3	12.5	3	1770	188		188	354	708
3	20	5	1648	177		177	330	659
3	20	4	1648	177		177	330	659
3	50	5	1526	166		166	305	610
4	5	3	2527	255		255	505	1011
4	5	2	2556	264		264	511	1022
4	12.5	5	1878	198		198	376	751
4	12.5	4	1878	198		198	376	751
4	20	5	1716	183		183	343	686
5	2	1	4887	489		489	977	1955
5	5	3	2798	279		279	560	1119
5	5	2	2827	288		288	565	1131
5	12.5	5	1986	207		207	397	794
5	12.5	4	1986	207		207	397	794
5	20	5	1783	189		189	357	713
6	2	1	5563	549		549	1113	2225
6	5	3	3098	313		313	620	1239
6	12.5	8	2094	217		217	419	838
6	12.5	7	2094	217		217	419	838
6	12.5	6	2094	217		217	419	838
6	12.5	5	2094	217		217	419	838
6	20	11	1851	195		195	370	740
6	20	10	1851	195		195	370	740

TABLE A.11. (Continued)

FACILITY SIZE (LT/D)	ACID GAS $\%H_2S$	SOUR GAS $\%H_2S$	CAPITAL COST[1]	ANNUAL O&M[2]	SULFUR CREDIT[3]	NET ANNUAL O&M	WORKING CAPITAL[4]	SALVAGE VALUE[5]
6	20	9	1851	195		195	370	740
6	20	8	1851	195		195	370	740
6	20	7	1851	195		195	370	740
6	20	6	1851	195		195	370	740
6	50	12	1607	173		173	321	643
6	50	11	1607	173		173	321	643
6	50	10	1607	173		173	321	643
6	80	12	1546	168		168	309	618
7	2	1	6240	610		610	1248	2496
7	5	3	3368	337		337	674	1347
7	5	2	3368	337		337	674	1347
7	12.5	8	2203	226		226	441	881
7	12.5	7	2203	226		226	441	881
7	12.5	6	2203	226		226	441	881
7	12.5	5	2203	226		226	441	881
7	20	12	1919	201		201	384	768
7	20	11	1919	201		201	384	768
7	20	10	1919	201		201	384	768
7	20	9	1919	201		201	384	768
7	20	8	1919	201		201	384	768
7	20	7	1919	201		201	384	768
7	50	12	1634	176		176	327	654
7	50	11	1634	176		176	327	654
7	50	10	1634	176		176	327	654
7	80	12	1563	170		170	313	625
7	80	11	1563	170		170	313	625
10	2	1	11277	1741	156	1585	2255	4511
10	5	3	6581	1281	171	1110	1316	2632
10	5	2	6611	1301	171	1130	1322	2644
10	12.5	6	4980	1057	184	873	996	1992
10	12.5	5	5009	1066	184	882	1002	2004
10	20	9	4433	924	185	739	887	1773
10	20	8	4433	924	185	739	887	1773
10	20	7	4433	924	185	739	887	1773
10	50	12	3537	756	188	568	707	1415
10	50	11	3537	756	188	568	707	1415
10	80	12	2890	707	191	516	578	1156
10	80	11	2890	707	191	516	578	1156
20	12.5	7	7323	1286	376	910	1465	2929
20	20	11	6119	1031	380	651	1224	2448
20	50	12	4653	763	384	379	931	1861
20	80	12	3742	545	389	156	748	1497
30	12.5	8	9321	1471	563	908	1864	
30	12.5	7	9321	1471	563	908	1864	
30	20	13	7450	1080	569	511	1490	
30	20	12	7450	1080	569	511	1490	

TABLE A.11. (Continued)

FACILITY SIZE (LT/D)	ACID GAS %H_2S	SOUR GAS %H_2S	CAPITAL COST 1/	ANNUAL O&M 2/	SULFUR CREDIT 3/	NET ANNUAL O&M	WORKING CAPITAL 4/	SALVAGE VALUE 5/
30	20	11	7450	1080	569	511	1490	
30	50	19	5277	733	577	156	1055	
30	80	19	3958	487	583	-96	792	
40	12.5	8	11306	1670	752	918	2261	
40	20	13	8780	1118	758	360	1756	
40	20	12	8780	1118	758	360	1756	
40	50	19	5903	684	769	-85	1181	
40	80	19	4244	425	777	-352	849	
50	12.5	8	13260	1872	939	933	2652	
50	20	14	10111	1177	948	229	2022	
50	20	13	10111	1177	948	229	2022	
50	50	19	6511	647	961	-314	1302	
50	80	19	4631	349	971	-622	926	
75	12.5	9	18255	2312	1409	903	3651	
75	20	14	13467	1320	1422	-102	2693	
75	50	19	8268	537	1442	-905	1654	
100	20	15	18229	1382	1896	-514	3646	

1/ For the derivation of these costs see Docket A-80-20-A.

2/ Ibid.

3/ Assumes 75% capacity utilization.

4/ Calculated at 20% of capital costs.

5/ Calculated at 40% of capital costs.

TABLE A.12. REGULATORY ALTERNATIVE III COSTS
($1000-1984)

FACILITY SIZE (LT/D)	ACID GAS %H_2S	SOUR GAS %H_2S	CAPITAL COST[1/]	ANNUAL O&M[2/]	SULFUR CREDIT[3/]	NET ANNUAL O&M	WORKING CAPITAL[4/]	SALVAGE VALUE[5/]
2	2	1	3797	911		911	759	1519
2	5	3	2717	733		733	543	1087
2	5	2	2717	733		733	543	1087
2	5	1	2746	742		742	549	1098
2	12.5	5	2219	655		655	444	888
2	12.5	4	2228	663		663	446	891
2	12.5	3	2228	663		663	446	891
2	12.5	2	2228	663		663	446	891
2	12.5	1	2257	672		672	451	903
2	20	5	2147	656		656	429	859
2	20	4	2147	656		656	429	859
2	20	3	2147	656		656	429	859
2	20	2	2147	656		656	429	859
2	20	1	2176	665		665	435	870
2	50	5	2066	649		649	413	826
2	50	4	2066	649		649	413	826
2	80	5	2046	647		647	409	818
3	2	1	4812	1041		1041	962	1925
3	5	3	3249	780		780	650	1300
3	5	2	3249	780		780	650	1300
3	12.5	5	2557	712		712	511	1023
3	12.5	4	2557	712		712	511	1023
3	12.5	3	2557	712		712	511	1023
3	20	5	2435	701		701	489	974
3	20	4	2435	701		701	489	974
3	50	5	2313	690		690	462	924
4	5	3	3781	832		832	756	1512
4	5	2	3810	841		841	762	1524
4	12.5	5	2936	748		748	587	1174
4	12.5	4	2936	748		748	587	1174
4	20	5	2774	733		733	555	1110
5	2	1	6871	1278	79	1199	1374	2748
5	5	3	4324	880	86	794	865	1730
5	5	2	4353	889	86	803	871	1741
5	12.5	5	3283	799	90	709	657	1313
5	12.5	4	3283	799	90	709	657	1313
5	20	5	3080	781	93	688	616	1232
6	2	1	8081	1396	98	1298	1616	3232
6	5	3	4802	953	107	846	960	1921
6	12.5	8	3427	888	111	777	685	1371
6	12.5	7	3427	888	111	777	685	1371
6	12.5	6	3427	888	111	777	685	1371
6	12.5	5	3427	888	111	777	685	1371
6	20	11	3184	866	116	750	637	1274

TABLE A.12. (Continued)

FACILITY SIZE (LT/D)	ACID GAS %H_2S	SOUR GAS %H_2S	CAPITAL COST 1/	ANNUAL O&M 2/	SULFUR CREDIT 3/	NET ANNUAL O&M	WORKING CAPITAL 4/	SALVAGE VALUE 5/
6	20	10	3184	866	116	750	637	1274
6	20	9	3184	866	116	750	637	1274
6	20	8	3184	866	116	750	637	1274
6	20	7	3184	866	116	750	637	1274
6	20	6	3184	866	116	750	637	1274
6	50	12	2940	844	116	728	588	1176
6	50	11	2940	844	116	728	588	1176
6	50	10	2940	844	116	728	588	1176
6	80	12	2879	839	116	723	576	1152
7	2	1	9052	1502	113	1389	1810	3621
7	5	3	5250	1049	124	925	1050	2100
7	5	2	5250	1049	124	925	1050	2100
7	12.5	8	3751	934	129	805	750	1500
7	12.5	7	3751	934	129	805	750	1500
7	12.5	6	3751	934	129	805	750	1500
7	12.5	5	3751	934	129	805	750	1500
7	20	12	3467	909	135	774	693	1387
7	20	11	3467	909	135	774	693	1387
7	20	10	3467	909	135	774	693	1387
7	20	9	3467	909	135	774	693	1387
7	20	8	3467	909	135	774	693	1387
7	20	7	3467	909	135	774	693	1387
7	50	12	3182	884	143	741	636	1273
7	50	11	3182	884	143	741	636	1273
7	50	10	3182	884	143	741	636	1273
7	80	12	3111	878	135	743	622	1244
7	80	11	3111	878	135	743	622	1244
10	2	1	11964	1812	162	1650	2393	4786
10	5	3	7069	1330	177	1153	1414	2828
10	5	2	7099	1350	177	1173	1420	2840
10	12.5	6	4609	1074	185	889	922	1844
10	12.5	5	4638	1083	185	898	928	1855
10	20	9	4150	957	193	764	830	1660
10	20	8	4150	957	193	764	830	1660
10	20	7	4150	957	193	764	830	1660
10	50	12	3940	885	193	692	788	1576
10	50	11	3940	885	193	692	788	1576
10	80	12	3838	876	193	683	768	1535
10	80	11	3838	876	193	683	768	1535
20	12.5	7	7291	1236	377	859	1458	2916
20	20	11	5977	1288	395	893	1195	2390
20	50	12	4064	707	398	309	813	1626
20	80	12	3861	669	398	271	772	1544
30	12.5	8	9277	1429	603	826	1855	
30	12.5	7	9277	1429	603	826	1855	

TABLE A.12. (Continued)

FACILITY SIZE (LT/D)	ACID GAS %H_2S	SOUR GAS %H_2S	CAPITAL COST 1/	ANNUAL O&M 2/	SULFUR CREDITS 3/	NET ANNUAL O&M	WORKING CAPITAL 4/	SALVAGE VALUE 5/
30	20	13	7919	1349	593	756	1584	
30	20	12	7919	1349	593	756	1584	
30	20	11	7919	1349	593	756	1584	
30	50	19	5255	721	597	124	1051	
30	80	19	4950	694	597	97	990	
40	12.5	8	11295	1643	755	888	2259	
40	20	13	9685	1409	791	618	1937	
40	20	12	9685	1409	791	618	1937	
40	50	19	6393	755	796	-41	1279	
40	80	19	5988	719	797	-78	1198	
50	12.5	8	13282	1836	944	892	2656	
50	20	14	11354	1468	989	479	2271	
50	20	13	11354	1468	989	479	2271	
50	50	19	7405	779	995	-216	1481	
50	80	19	6398	734	995	-261	1280	
75	12.5	9	18250	2321	1416	905	3650	
75	20	14	15244	1640	1483	157	3049	
75	50	19	9728	840	1492	-652	1946	
100	20	15	20158	1754	1977	-223	4032	

1/ For the derivation of these costs see Docket A-80-20-A.

2/ Ibid.

3/ Assumes 75% capacity utilization.

4/ Calculated at 20% of capital costs.

5/ Calculated at 40% of capital costs.

This estimate has been made by taking the inverse of the price/ earnings ratio of 8.0 noted in Table 9-14, page 9-32, of the proposal BID. This method is acceptable for making approximations of this rate because given a specific stream of earnings, the price of a firm's security should adjust until an acceptable return becomes available to potential investors.

In order to convert the nominal returns noted into real rates of return, an assumption about current and future rates of inflation must be made. For purposes of this analysis, an annual inflation rate of 5% is used, based upon recent increases in the Consumer Price Index. Subtracting this rate from the nominal rates of return noted above provides real rates of return of 6.0 and 7.5% for interest and equity, respectively. These rates appear realistic and reflect the greater risk inherent in investments in the oil and gas industry.

In addition to the above, it has been assumed that debt incurred by the plant will be repaid over a period equal to half the operating life of the facility. Therefore, plants equal to or less than 20 LT/D would repay loans over 6 years, while plants greater than 20 LT/D would repay loans over 10 years.

Finally, it is assumed that royalty payments of 12.5% of gross revenues are paid by the lessee to the lessor (i.e., owner).[3] Due to the difficulties inherent in calculating depletion exemptions, such as calculation of land costs and costs of mineral rights, a depletion allowance has not been included in this analysis. This amounts to is an overstatement of taxes and is, therefore, a conservative assumption with regard to financial viability.

A.5 Discounted Cash Flow Analysis

The discounted cash flow (DCF) analysis has five major steps:

1) Estimate the costs for the baseline and Regulatory Alternative III, for each model plant (operating at 75% capacity) and each acid gas percent.
2) Estimate the revenues for various combinations of model plant size, acid gas percent, and sour gas percent assuming 75% capacity utilization and 5% severance tax.
3) Eliminate from further consideration cases that are economically

infeasible in the baseline. Elimination is based on a rough approximation of net present value, made by examination of annuity factors, and allows for the elimination of approximately 5% of all situations presented in Table A.13. This reduces the number of cases that need to be evaluated through the DCF computer model.

4) Estimate the net present value (i.e., economic feasiblity) of remaining cases under both the baseline and Regulatory Alternative III, and

5) Evaluate the economic impacts based upon the results of the net present value (i.e., discounted cash flow) analysis, and sulfur content probability tables.

For those cases that remain after the screening process described above, the DCF model is used to distinguish three groups of facilities: 1) those that are not economically feasible under the baseline, 2) those that are economically feasible under the baseline but are not economically feasible under Regulatory Alternative III, and 3) those that are economically feasible under both the baseline and Regulatory Alternative III. The identification of plants fitting the second of these groups is the primary purpose of this analysis. Finally, in order to evaluate the potential for economic impacts (i.e., postponement of new plant construction, supply restrictions, and price increases) the probability tables are consulted to determine the probability that new plants would display the acid and sour gas characteristics of those plants falling into the second group noted above.

A.6 Discounted Cash Flow Analysis Results

By way of example, the analysis and results for the 2 LT/D, 5% acid gas plant are presented in detail on the following tables. This size category provides a good example because plants fitting each of the three groups noted above can be observed. Plants that are 2 LT/D, 5% acid gas, and either 5% or 4% sour gas were not run on the DCF model because the screening analysis showed the baseline cases to be uneconomicial. The 2 LT/D, 5% acid gas, 3% sour gas case, see Table A.14, was run and shown to be economically feasible under the baseline situation. This can be observed by noting that the net present value at the end of 10 years was $388.65 thousand. Under Regulatory Alternative III, see Table A.15, this situation changed and the plant was no longer economically feasible. Note the negative

TABLE A.13.

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TABLE A.14.

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                      2LT/DAY. 5% ACID GAS. 3% SOUR GAS
               DISCOUNTED CASH FLOW ANALYSIS FOR ALTERNATIVE I
   ANALYSIS IN CONSTANT DOLLARS (UNITS EXPRESSED AS THOUSANDS OF 1984 DOLLARS)
NEW FINANCING: PERCENT DEBT       50.00          INVESTMENT: EQUIPMENT    1936.00
               PERCENT EQUITY     50.00                      BUILDINGS        .00
               PERCENT CNT.DBT.     .00                      LAND             .00
               PERCENT CNT.EQ.      .00                      WORKING CAP.  387.00
                                                             CNT.EQUIP.       .00
YEAR                         1          2          3          4          5
REVENUES                423.00     443.00     463.00     484.00     507.00
O&M COSTS               179.00     179.00     179.00     179.00     179.00
DEPRECIATION            387.20     398.82     421.44     267.58     127.42
INTEREST                 69.69      56.86      44.54      32.72      21.38
CONTROL O&M COSTS          .00        .00        .00        .00        .00
EARNINGS BEFORE TAX    -212.89    -191.68    -181.99       4.69     179.20
DEPLETION                  .00        .00        .00        .00        .00
TAX LOSS                   .00        .00        .00      -4.69    -179.20
TAX RATE                .00000     .00000     .00000     .00000     .00000
TAX LIABILITY              .00        .00        .00        .00        .00
INVESTMENT TAX CDT.        .00        .00        .00        .00        .00
MINIMUM TAX                .00        .00        .00        .00        .00
TOTAL TAX DUE              .00        .00        .00        .00        .00
EARNINGS AFTER TAX     -212.89    -191.68    -181.99       4.69     179.20
DEPRECIATION            387.20     398.82     421.44     267.58     127.42
DEPLETION                  .00        .00        .00        .00        .00
CASH FLOW BEF.DEDT.     174.31     207.14     239.46     272.28     306.62
REQ. PRINCIPAL          166.52     168.10     169.70     171.32     172.95
SUS.CAP.EXP.               .00        .00        .00        .00        .00
XTRA.CASH IN-FLOWS         .00        .00        .00        .00        .00
WORK.CAP.RECOVERY          .00        .00        .00        .00        .00
NET CASH FLOW             7.79      39.04      69.75     100.96     133.67
DISCOUNT FACTOR         .93023     .86533     .80496     .74880     .69656
DSCT.NET CASH FLOW        7.25      33.78      56.15      75.60      93.11

YEAR                         6          7          8          9         10
REVENUES                530.00     554.00     580.00     606.00     634.00
O&M COSTS               179.00     179.00     179.00     179.00     179.00
DEPRECIATION               .00        .00        .00        .00        .00
INTEREST                 10.48        .00        .00        .00        .00
CONTROL O&M COSTS          .00        .00        .00        .00        .00
EARNINGS BEFORE TAX     340.52     375.00     401.00     427.00     455.00
DEPLETION                  .00        .00        .00        .00        .00
TAX LOSS               -340.52    -255.33        .00        .00        .00
TAX RATE                .00000     .34337     .45958     .46258     .46549
TAX LIABILITY              .00      41.80     184.26     197.52     211.80
INVESTMENT TAX CDT.        .00      39.28     100.18        .00        .00
MINIMUM TAX                .00        .00        .00        .00        .00
TOTAL TAX DUE              .00       2.52      84.08     197.52     211.80
EARNINGS AFTER TAX      340.52     372.48     316.92     229.48     243.20
DEPRECIATION               .00        .00        .00        .00        .00
DEPLETION                  .00        .00        .00        .00        .00
CASH FLOW BEF.DEDT.     340.52     372.48     316.92     229.48     243.20
REQ. PRINCIPAL          174.60        .00        .00        .00        .00
SUS.CAP.EXP.               .00        .00        .00        .00        .00
XTRA.CASH IN-FLOWS         .00        .00        .00        .00        .00
WORK.CAP.RECOVERY          .00        .00        .00        .00        .00
NET CASH FLOW           165.92     372.48     316.92     229.48     243.20
DISCOUNT FACTOR         .64796     .60276     .56070     .52158     .48519
DSCT.NET CASH FLOW      107.51     224.51     177.70     119.69     118.00

YEAR                        11         12
REVENUES                634.00     634.00
O&M COSTS               179.00     179.00
DEPRECIATION               .00        .00
INTEREST                   .00        .00
CONTROL O&M COSTS          .00        .00
EARNINGS BEFORE TAX     455.00     455.00
DEPLETION                  .00        .00
TAX LOSS                   .00        .00
TAX RATE                .46549     .46549
TAX LIABILITY           211.80     211.80
INVESTMENT TAX CDT.        .00        .00
MINIMUM TAX                .00        .00
TOTAL TAX DUE           211.80     211.80
EARNINGS AFTER TAX      243.20     243.20
DEPRECIATION               .00        .00
DEPLETION                  .00        .00
CASH FLOW BEF.DEDT.     243.20     243.20
REQ. PRINCIPAL             .00        .00
SUS.CAP.EXP.               .00        .00
XTRA.CASH IN-FLOWS         .00     387.00
WORK.CAP.RECOVERY          .00     387.00
NET CASH FLOW           243.20    1017.20
DISCOUNT FACTOR         .45134     .41986
DSCT.NET CASH FLOW      109.77     427.08
    PRESENT VALUE OF CASH FLOWS FOR 12 YEARS IS                    1550.15
    LESS EQUITY SHARE OF ORIGINAL INVESTMENT                       1161.50
    NET PRESENT VALUE IS                                            388.65
    THE IRR IS  11.12 PERCENT
  SINCE WORKING CAPITAL IS RECOVERED IT IS
[illegible]
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TABLE A.15.

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                          25T/DAY. 5% ACID GAS. 5% SOUR GAS
                 DISCOUNTED CASH FLOW ANALYSIS FOR ALTERNATIVE III
  ANALYSIS IN CONSTANT DOLLARS (UNITS EXPRESSED AS THOUSANDS OF 1984 DOLLARS)
NEW FINANCING: PERCENT DEBT         50.00          INVESTMENT: EQUIPMENT     2667.00
               PERCENT EQUITY       50.00                      BUILDINGS         .00
               PERCENT CNT.DBT.       .00                      LAND              .00
               PERCENT CNT.EQ.        .00                      WORKING CAP.   533.00
YEAR                                                           CNT.EQUIP.        .00
REVENUES                  1           2           3           4           5
O&M COSTS            423.00      445.00      463.00      464.00      587.00
DEPRECIATION         785.00      785.00      785.00      785.00      785.00
INTEREST             533.40      811.80      588.57      348.62      175.55
CONTROL O&M COSTS     96.80       78.32       61.36       45.08       29.45
EARNINGS BEFORE TAX     .00         .00         .00         .00         .00
DEPLETION           -911.40    -1152.12     -883.93     -614.70     -403.00
TAX LOSS                .00         .00         .00         .00         .00
TAX RATE                .00         .00         .00         .00         .00
TAX LIABILITY        .00000      .00000      .00000      .00000      .00000
INVESTMENT TAX CDT.     .00         .00         .00         .00         .00
MINIMUM TAX             .00         .00         .00         .00         .00
TOTAL TAX DUE           .00         .00         .00         .00         .00
EARNINGS AFTER TAX      .00         .00         .00         .00         .00
DEPRECIATION        -911.40    -1152.12     -883.93     -614.70     -403.00
DEPLETION            533.40      811.80      588.57      348.62      175.55
CASH FLOW BEF.DEDT.     .00         .00         .00         .00         .00
REG. PRINCIPAL      -378.00     -340.32     -295.36     -266.08     -227.45
SUS.CAP.EXP.         229.38      231.57      241.77      236.00      238.24
XTRA.CASH IN-FLOWS      .00         .00         .00         .00         .00
WORK.CAP.RECOVERY       .00         .00         .00         .00         .00
NET CASH FLOW           .00         .00         .00         .00         .00
DISCOUNT FACTOR     -607.38     -571.89     -537.13     -502.08     -465.69
DSCT.NET CASH FLOW   .93023      .86533      .80496      .74880      .69656
                    -565.01     -494.87     -432.37     -375.96     -324.38

YEAR
REVENUES                  6           7           8           9          10
O&M COSTS            530.00      554.00      580.00      686.00      634.00
DEPRECIATION         785.00      785.00      785.00      785.00      785.00
INTEREST                .00         .00         .00         .00         .00
CONTROL O&M COSTS     14.43         .00         .00         .00         .00
EARNINGS BEFORE TAX     .00         .00         .00         .00         .00
DEPLETION           -189.43     -151.00     -125.00      -99.00      -71.00
TAX LOSS                .00         .00         .00         .00         .00
TAX RATE                .00         .00         .00         .00         .00
TAX LIABILITY        .00000      .00000      .00000      .00000      .00000
INVESTMENT TAX CDT.     .00         .00         .00         .00         .00
MINIMUM TAX             .00         .00         .00         .00         .00
TOTAL TAX DUE           .00         .00         .00         .00         .00
EARNINGS AFTER TAX      .00         .00         .00         .00         .00
DEPRECIATION        -189.43     -151.00     -125.00      -99.00      -71.00
DEPLETION               .00         .00         .00         .00         .00
CASH FLOW BEF.DEDT.     .00         .00         .00         .00         .00
REG. PRINCIPAL      -189.43     -151.00     -125.00      -99.00      -71.00
SUS.CAP.EXP.         240.51         .00         .00         .00         .00
XTRA.CASH IN-FLOWS      .00         .00         .00         .00         .00
WORK.CAP.RECOVERY       .00         .00         .00         .00         .00
NET CASH FLOW           .00         .00         .00         .00         .00
DISCOUNT FACTOR     -429.94     -151.00     -125.00      -99.00      -71.00
DSCT.NET CASH FLOW   .64796      .60276      .56070      .52158      .48519
                    -278.59      -91.02      -70.09      -51.64      -34.45

YEAR
REVENUES                 11          12
O&M COSTS            634.00      634.00
DEPRECIATION         785.00      785.00
INTEREST                .00         .00
CONTROL O&M COSTS       .00         .00
EARNINGS BEFORE TAX     .00         .00
DEPLETION            -71.00      -71.00
TAX LOSS                .00         .00
TAX RATE                .00         .00
TAX LIABILITY        .00000      .00000
INVESTMENT TAX CDT.     .00         .00
MINIMUM TAX             .00         .00
TOTAL TAX DUE           .00         .00
EARNINGS AFTER TAX      .00         .00
DEPRECIATION         -71.00      -71.00
DEPLETION               .00         .00
CASH FLOW BEF.DEDT.     .00         .00
REG. PRINCIPAL       -71.00      -71.00
SUS.CAP.EXP.            .00         .00
XTRA.CASH IN-FLOWS      .00         .00
WORK.CAP.RECOVERY       .00      533.00
NET CASH FLOW           .00      533.00
DISCOUNT FACTOR      -71.00      995.00
DSCT.NET CASH FLOW   .45134      .41986
                     -32.05      417.76
  PRESENT VALUE OF CASH FLOWS FOR 12 YEARS IS                    -2332.65
  LESS EQUITY SHARE OF ORIGINAL INVESTMENT                        1600.00
  NET PRESENT VALUE IS                                           -3932.65
  THE IRR IS      .00 PERCENT
 SINCE WORKING CAPITAL IS RECOVERED IT IS
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net present value ($-3932.65 thousand). The third situation is shown on Table A.16. Here the 2 LT/D, 5% acid gas, 2% sour gas case is economically feasible under Regulatory Alternative III with a positive net present value of $1865.15 thousand. In this situation, there is no need to run the DCF model for the baseline case since the costs are less than under the NSPS case.

In total, 27 plants were found to be economically feasible under the baseline conditions, but economically infeasible under Regulatory Alternative III. The data for these 27 plants were transformed into ranges of facility size, H_2S concentrations in the acid gas, and H_2S concentrations in the sour gas. These plants are identified in Table A.17. As can be seen on this table the aggregate probabilities range from .0140 to .0799. These low probabilities indicate that plants with these gas quality combinations have a very low probability of being developed. If these aggregate probabilities by size categories are then multiplied by the number of facilities projected between 1985-1995 for each size category, the number of expected impacted facilities can be observed. Over the ten year period of this analysis the total number of expected adversely impacted facilities, for all size categories, is 4.4. If these expected new facilities were in fact not built due to the adverse economic affects of the NSPS it would amount to approximately 1.4 X 10^9 SCF/year of sweet gas curtailed over the 10 year period. To put this in perspective the potential gas curtailed amounts to .01% of the projected total new gas production of approximately 10,000 X 10^9 SCF/year.

The basic conclusion of this analysis is that the NSPS is not expected to cause the delay or cancellation of onshore processing facilities currently projected to be constructed over the next ten years. Although the analysis has identified a limited number of situations in which the NSPS would preclude the development of otherwise economically feasible facilities, it is highly unlikely that new facilities will display sulfur content levels similar to those model plants shown to be adversely affected.

TABLE A.16.

```
                     2LT/DAY. 5% ACID GAS. 3% SOUR GAS
              DISCOUNTED CASH FLOW ANALYSIS FOR ALTERNATIVE III
   ANALYSIS IN CONSTANT DOLLARS (UNITS EXPRESSED AS THOUSANDS OF 1984 DOLLARS)
 NEW FINANCING: PERCENT DEBT        50.00
                PERCENT EQUITY      50.00        INVESTMENT: EQUIPMENT     2667.00
                PERCENT CNT.DBT.      .00                    BUILDINGS         .00
                PERCENT CNT.EQ.       .00                    LAND              .00
 YEAR                                                        WORKING CAP.   533.00
 REVENUES                                                    CNT.EQUIP.        .00
                            1            2            3            4            5
 REVENUES             1211.00      1267.00      1325.00      1386.00      1458.00
 O&M COSTS             705.00       705.00       705.00       705.00       705.00
 DEPRECIATION          543.40       812.00       580.57       348.62       175.55
 INTEREST               96.00        79.12        61.36        55.08        37.44
 CONTROL O&M COSTS        .00          .00          .00          .00          .00
 EARNINGS BEFORE TAX  -133.40      -329.12       -21.93       277.30       540.01
 DEPLETION                .00          .00          .00          .00          .00
 TAX LOSS                 .00          .00          .00      -277.30      -207.15
 TAX RATE              .00000       .00000       .00000       .00000       .44917
 TAX LIABILITY            .00          .00          .00          .00       149.51
 INVESTMENT TAX CDT.      .00          .00          .00          .00       130.83
 MINIMUM TAX              .00          .00          .00          .00          .00
 TOTAL TAX DUE            .00          .00          .00          .00        18.68
 EARNINGS AFTER TAX   -133.40      -329.12       -21.93       277.30       521.33
 DEPRECIATION          543.40       812.00       580.57       348.62       175.55
 DEPLETION                .00          .00          .00          .00          .00
 CASH FLOW BEF.DEDT.   410.00       482.88       558.64       625.92       696.88
 REG. PRINCIPAL        229.38       230.77       233.77       226.00       238.25
 SUS.CAP.EXP.             .00          .00          .00          .00          .00
 XTRA.CASH IN-FLOWS       .00          .00          .00          .00          .00
 WORK.CAP.RECOVERY        .00          .00          .00          .00          .00
 NET CASH FLOW         180.62       252.11       324.87       399.92       458.63
 DISCOUNT FACTOR       .93023       .86533       .80496       .74880       .69656
 DSCT.NET CASH FLOW    168.02       218.16       261.51       299.46       319.46

 YEAR                       6            7            8            9           10
 REVENUES             1517.00      1586.00      1659.00      1736.00      1816.00
 O&M COSTS             705.00       705.00       705.00       705.00       705.00
 DEPRECIATION             .00          .00          .00          .00          .00
 INTEREST               14.43          .00          .00          .00          .00
 CONTROL O&M COSTS        .00          .00          .00          .00          .00
 EARNINGS BEFORE TAX   797.57       881.00       954.00      1031.00      1111.00
 DEPLETION                .00          .00          .00          .00          .00
 TAX LOSS                 .00          .00          .00          .00          .00
 TAX RATE              .48461       .48701       .48877       .49036       .49177
 TAX LIABILITY         386.51       429.06       466.29       505.56       546.36
 INVESTMENT TAX CDT.    84.36          .00          .00          .00          .00
 MINIMUM TAX              .00          .00          .00          .00          .00
 TOTAL TAX DUE         302.15       429.06       466.29       505.56       546.36
 EARNINGS AFTER TAX    495.42       451.94       487.71       525.44       564.64
 DEPRECIATION             .00          .00          .00          .00          .00
 DEPLETION                .00          .00          .00          .00          .00
 CASH FLOW BEF.DEDT.   495.42       451.94       487.71       525.44       564.64
 REG. PRINCIPAL        240.51          .00          .00          .00          .00
 SUS.CAP.EXP.             .00          .00          .00          .00          .00
 XTRA.CASH IN-FLOWS       .00          .00          .00          .00          .00
 WORK.CAP.RECOVERY        .00          .00          .00          .00          .00
 NET CASH FLOW         254.90       451.94       487.71       525.44       564.64
 DISCOUNT FACTOR       .64796       .60276       .56070       .52158       .48519
 DSCT.NET CASH FLOW    165.17       272.41       273.46       274.06       273.96

 YEAR                      11           12
 REVENUES             1816.00      1816.00
 O&M COSTS             705.00       705.00
 DEPRECIATION             .00          .00
 INTEREST                 .00          .00
 CONTROL O&M COSTS        .00          .00
 EARNINGS BEFORE TAX  1111.00      1111.00
 DEPLETION                .00          .00
 TAX LOSS                 .00          .00
 TAX RATE              .49177       .49177
 TAX LIABILITY         546.36       546.36
 INVESTMENT TAX CDT.      .00          .00
 MINIMUM TAX              .00          .00
 TOTAL TAX DUE         546.36       546.36
 EARNINGS AFTER TAX    564.64       564.64
 DEPRECIATION             .00          .00
 DEPLETION                .00          .00
 CASH FLOW BEF.DEDT.   564.64       564.64
 REG. PRINCIPAL           .00          .00
 SUS.CAP.EXP.             .00          .00
 XTRA.CASH IN-FLOWS       .00       533.00
 WORK.CAP.RECOVERY        .00       533.00
 NET CASH FLOW         564.64      1630.64
 DISCOUNT FACTOR       .45134       .41986
 DSCT.NET CASH FLOW    254.85       684.63
   PRESENT VALUE OF CASH FLOWS FOR 12 YEARS IS                          3465.15
   LESS EQUITY SHARE OF ORIGINAL INVESTMENT                             1600.00
   NET PRESENT VALUE IS                                                 1865.15
   THE IRR IS  28.90 PERCENT
  SINCE WORKING CAPITAL IS RECOVERED IT IS
SSUMED THAT THE PROJECT TERMINATES AT THE END OF THE
PROJECT LIFE. SO TERMINAL VALUE IS NOT APPLICABLE.
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TABLE A.17 SUMMARY OF PLANTS MADE ECONOMICALLY INFEASIBLE BY REGULATORY ALTERNATIVE III[1/]

Average Sweet Gas Flow per Facility 10^9 SCF/Y	Facility Size		Mole % H_2S		Maximum Probability	10 Year Projected # Facilities	Potentially Affected # Facilities	Sweet Gas Flow 10^9 SCF/Y
	LT/d	Mg/d	Acid Gas	Sour Gas				
0.2244	1.08-1.97	1.1-2.0	2-50	2-12.5	0.0301	16.5	0.497	0.111
0.2673	2.07-2.95	2.1-3.0	2-20	2-12.5	0.0260	11.5	0.308	0.082
0.3565	3.05-3.94	3.1-4.0	2-20	2-12.5	0.0342	10.5	0.359	0.128
0.4155	4.04-4.92	4.1-5.0	2-12.5	2-5	0.0140	9.5	0.133	0.055
0.3107	5.02-9.04	5.1-8.0	2-100.0	2-12.5	0.0799	37.0	2.956	0.918
0.4861	39.27-49.2	40.1-60	12.5-50.0	12.5-20.0	0.0392	3.2	0.125	0.061
				Total	0.2102		4.378	1.355

[1/] See docket entry IV-B-28 for detail on the sour gas characteristic frequency distributions.

REFERENCES FOR APPENDIX A

1. State Tax Guide - All States, Volume 2, Commerce Clearing House, Inc., 1984.

2. Chase Energy Economics, Financial Analysis of a Group of Petroleum Companies, 1981, p. 25. Docket No. A-80-20-A.

3. Personal communication between Janet Scheid of U.S.E.P.A. with Dr. Edward Erickson, North Carolina State University, January 1985.

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-450/3-82-023b	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE SO_2 Emissions in Natural Gas Production Industry - Background Information for Promulgated Standards		5. REPORT DATE September 1985
		6. PERFORMING ORGANIZATION CODE
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15. SUPPLEMENTARY NOTES This document presents the background information used by the Environmental Protection Agency in developing the final new source performance standards for emissions of sulfur dioxide from the natural gas processing industry.

16. ABSTRACT

Standards of performance for the control of sulfur dioxide (SO_2) emissions from the natural gas processing industry are being promulgated under Section 111 of the Clean Air Act. These standards will apply to SO_2 emissions from newly constructed, modified, and reconstructed sweetening and sulfur recovery units in onshore natural gas processing plants. This document summarizes the responses to public comments received on the proposed standards and the basis for changes made since proposal.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution Natural Gas Processing Pollution Control Standards of Performance Sulfur Dioxide (SO_2)	Air Pollution Control	13b

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